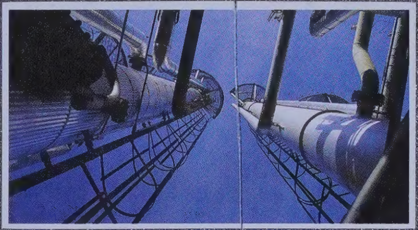
PARAMOUNT RESOURCES LTD.

25 YEARS

2003



ANNUAL REPORT

TSX
POU

25 YEAR STOCK PERFORMANCE ($/share)
(annual average)

78[1]	1.00
79[1]	1.17
80	0.85
81	0.64
82	0.60
83	0.60
84	0.53
85	0.88
86	0.78
87	0.72
88	0.88
89	2.42
90	2.96
91	2.90
92	2.67
93	6.15
94	6.00
95	4.58
96	6.67
97	12.75
98	14.00
99	19.00
00	15.25
01	15.38
02	15.30
03[2]	14.87

(1) estimates of average annual share price
(2) 2003 low adjusted upward by $4.28/share to reflect the share price drop associated with the dividend of Paramount Energy Trust

**IT'S NOT ABOUT TODAY.
IT NEVER HAS BEEN.
IT'S ABOUT THE LONG TERM.**

**TAKE A LOOK AT THE 25 YEARS
OF OUR COMPANY AND YOU
WILL SEE FOR YOURSELF.**

THIS IS THE STORY OF PARAMOUNT.

Financial Highlights

($ thousands except per share amounts and where stated otherwise)	Year Ended December 31 2003	2002	% Change
Financial			
Gross revenue	**381,847**	473,942	**(19%)**
Cash flow			
From operations	**167,276**	259,916	**(36%)**
Per share – basic	**2.78**	4.37	**(36%)**
– diluted	**2.77**	4.36	**(36%)**
Earnings			
Net earnings	**2,633**	10,307	**(74%)**
Per share – basic	**0.04**	0.17	**(76%)**
– diluted	**0.04**	0.16	**(75%)**
Capital expenditures			
Exploration and development	**223,753**	217,196	**3%**
Summit acquisition	**–**	251,422	**(100%)**
Acquisitions, dispositions and other	**(368,731)**	25,917	**–**
Net capital expenditures	**(144,978)**	494,535	**–**
Total assets	**1,147,848**	1,526,786	**(25%)**
Net debt	**307,704**	555,243	**(45%)**
Shareholders' equity	**501,642**	546,105	**(8%)**
Weighted average common shares outstanding (thousands)	**60,098**	59,458	
Common shares outstanding at year-end (thousands)	**60,095**	59,459	
Common shares outstanding at March 12, 2004 (thousands)	**59,393**		
Operating			
Production			
Natural gas (MMcf/d)	**152.8**	241.4	**(37%)**
Crude oil and liquids (Bbl/d)	**7,169**	5,663	**27%**
Total production (Boe/d) @ 6:1	**32,630**	45,898	**(29%)**
Average prices			
Natural gas (pre-hedge) ($/Mcf)	**5.99**	3.53	**70%**
Natural gas ($/Mcf)	**5.16**	4.08	**26%**
Crude oil and liquids (pre-hedge) ($/Bbl)	**38.27**	35.20	**9%**
Crude oil and liquids ($/Bbl)	**35.50**	34.64	**2%**
Reserves (proved and probable)			
Natural gas (Bcf)	**329.4**	618.6	**(47%)**
Crude oil and liquids (MBbl)	**12,513**	22,846	**(45%)**
Estimated present value before tax discounted @ 10%			
Proved ($ millions)	**597**	983	**(39%)**
Proved and probable ($ millions)	**734**	1,258	**(42%)**
Land (thousands of acres)			
Total net land holdings	**3,386**	5,077	**(33%)**
Net undeveloped land holdings	**2,800**	3,545	**(21%)**
Drilling activity (gross)			
Gas	**180**	114	**58%**
Oil	**16**	9	**78%**
Other	**–**	1	**(100%)**
D&A	**15**	11	**36%**
Total wells	**211**	135	**56%**
Success rate	**93%**	92%	**1%**

Clay Riddell started Paramount as an idea 25 years ago and grew it to a company that produces 30,000 Boe/d. In addition, shareholders

have benefited from the distribution of the income generating Paramount Energy Trust, which at the time of creation produced

Letter to Shareholders

In December 2003 Paramount Resources Ltd. ("Paramount" or the "Company" or "we") celebrated its 25th Anniversary of business operations. This milestone calls for reflection on some of the Company's major accomplishments throughout its first 25 years in conjunction with, and in spite of, the major industry challenges the Company has successfully navigated. The most striking theme is that during this period less than a handful of our industry peers have emerged intact and, as in Paramount's case, have grown significantly. Many can compare an original total shareholder investment over this 25-year period of $200 million to the current enterprise value and see the tremendous value creation Paramount has achieved.

Paramount has grown from an idea in 1978 to a Company that produces over 30,000 Boe/d all from an initial public offering of $5 million. Paramount's success began with the development of the Grosmont carbonate trend in northeast Alberta, starting with the discovery at Liege, then the lower Mannville clastics trend and the discovery made at Chard; both of these discoveries grew into large areas of high deliverability, long reserve life shallow gas reserves in northeast Alberta. In the early nineties the Company successfully branched out into central Alberta with successful exploration and development programs at Kaybob which has now grown into Paramount's largest producing core area. The northern development, which began with the Zama Lake properties, now ranges from the Bistcho Lake area in northwest Alberta and extends north into the Cameron Hills area of the Northwest Territories in 2002. Paramount built the transborder pipeline to cross from Alberta into the Northwest Territories to bring the first natural gas production from Cameron Hills. Similarly, Paramount's development in northeast British Columbia that extends north into the southern Northwest Territories at Fort Liard included the construction of a transborder pipeline to produce gas from the Liard discovery. We have continued our penchant for exploration to the north with our newest area of frontier exploration in the central Mackenzie Valley at Colville Lake in the Northwest Territories.

The growth in shareholder value has been achieved despite major governmental changes in the energy sector; some not so conducive to the success of the oil and gas industry. In the early nineties the National Energy Program (NEP) was introduced with crippling effects on the Canadian oil and gas industry. Then we had a regulated gas market that evolved into deregulation which created the Canadian gas bubble. We battled and thrived despite the suppressed prices in this newly deregulated market as reserve life restrictions relating to the regulation were eliminated and producers could accelerate the development of deliverability and market these reserves to meet export opportunities to the US. There has been a period of [illegible] drilling as the gas bubble in Canada has been eliminated, and supply and demand have balanced in North America. Most recently, a gas over bitumen issue has developed; producers like Paramount that have diligently explored, developed and produced from gas reserves coincident with bitumen leases have had their rights expropriated. The decisions rendered by the Alberta Energy and Utilities Board (AEUB) with respect to this issue have effectively destroyed the natural gas industry in northeast Alberta where Paramount had created a prosperous business and had inventoried a substantial resource and opportunity base.

The year 2003 was one of transition for Paramount as the Summit Resources Ltd. ("Summit") acquisition was fully integrated and the Company started to capitalize on the opportunities it had identified in these assets. Paramount's original shallow gas properties in northeast Alberta were distributed to the Company's shareholders through the creation of the income distributing Paramount Energy Trust that at the time of its creation was producing over 15,000 Boe/d. There was also a significant improvement in the strength of Paramount's balance sheet in 2003.

Paramount's net debt had been reduced from its peak of about $618 million at the time of the Summit acquisition in June 2002 to $555 million at December 31, 2002. This debt was further reduced through three separate dispositions: the additional assets sold to Paramount Energy Trust for $195 million, the non-core disposition package for $71 million and the sale of the Sturgeon Lake property for $54 million. The total disposition proceeds of $320 million reduced net debt to approximately $308 million by the end of 2003.

Further improvement of Paramount's financial flexibility was achieved by the Company's issuance of US$175 million of 7 7/8 percent Senior Notes due in 2010. This new financing combined with the Company's $203 million committed bank facility gives Paramount a total debt capacity of approximately $430 million with around $300 million utilized at year-end, leaving about $130 million available for use. This availability of capital has allowed Paramount to undertake an aggressive winter drilling program as well as evaluate potential acquisition opportunities.

The plan to integrate the Summit assets was successfully executed in 2003. The first step saw the rationalization of Summit's minor non-core properties, principally in the Southern area. This was achieved through a successful disposition program during the spring and summer of 2003 and raised $71 million. The second part of the plan involved the move to exploit the Kaybob asset base. A large part of the assets acquired through Summit fall within the areas Paramount has identified as being prospective for downspacing. Paramount started in the summer of 2003 and by year-end had drilled 50 downspacing wells in the general Kaybob area. To date, the tight lower Cretaceous reserves in the deep-basin portion of the Kaybob area had been exploited by drilling one well per section. Through the integration of geological and geophysical mapping and engineering decline-analysis, it became apparent that only a fraction of the original gas-in-place would be recovered with the drilling of one well per section. Original gas reserves can be in excess of 15 Bcf per section, however, a typical well may only produce two to five Bcf. To effectively drain the reservoirs, more than one well per section is required to deplete all of the gas reserves. It takes approximately three months between initiating drilling activities and the commencement of production. The downspacing drilling program started in the summer of 2003, the production growth from this program has only begun to be realized near the end of 2003 and into 2004. The third part of the integration plan was to explore the Summit assets in the Grande Prairie core area. Paramount was successful with the discovery of a shallow Dunvegan gas field at Mirage, which added over 10 MMcf/d of gas through the latter part of 2003. A further discovery was made at Saddle Hills, within the same core area, where a deeper Wabamun well was drilled and tested at 15 MMcf/d of natural gas and 300 Bbl/d of natural gas liquids. This well was tested and producing by late November 2003 at over 1,500 Boe/d.

Paramount has continued to advance its long-term projects at Colville Lake in the central Mackenzie Valley of the Northwest Territories. At Colville Lake, two successful gas wells were drilled and tested on the Nogha prospect in 2003 with results exceeding the Company's expectations. A further well was successfully drilled and cased at Nogha during the 2004 winter. Two additional prospects were tested in the 2004 winter. The exploration well further north at Manoir Ridge as well as the exploration well further west at West Nogha were both successfully drilled and cased as potential gas wells. At the time of writing, all three wells drilled during the winter of 2004 are undergoing completion operations. Success to date from exploration drilling at Colville Lake has now led to the evaluation of several development scenarios, including participation in the Mackenzie Valley Pipeline or possibly the construction of a dedicated 500 mile pipeline from Norman Wells south into Alberta to tie in to the existing pipeline infrastructure.

Another new project for Paramount tests the feasibility and potential bitumen reserves of its SAGD projects in northeast Alberta. The Company executed its first drilling program to start the delineation of our bitumen prospects in Northeast Alberta. A total of 12 wells were drilled during the 2004 winter program to delineate the bitumen reserves: seven wells at the Leismer prospect and five wells at the Company's Surmont prospect.

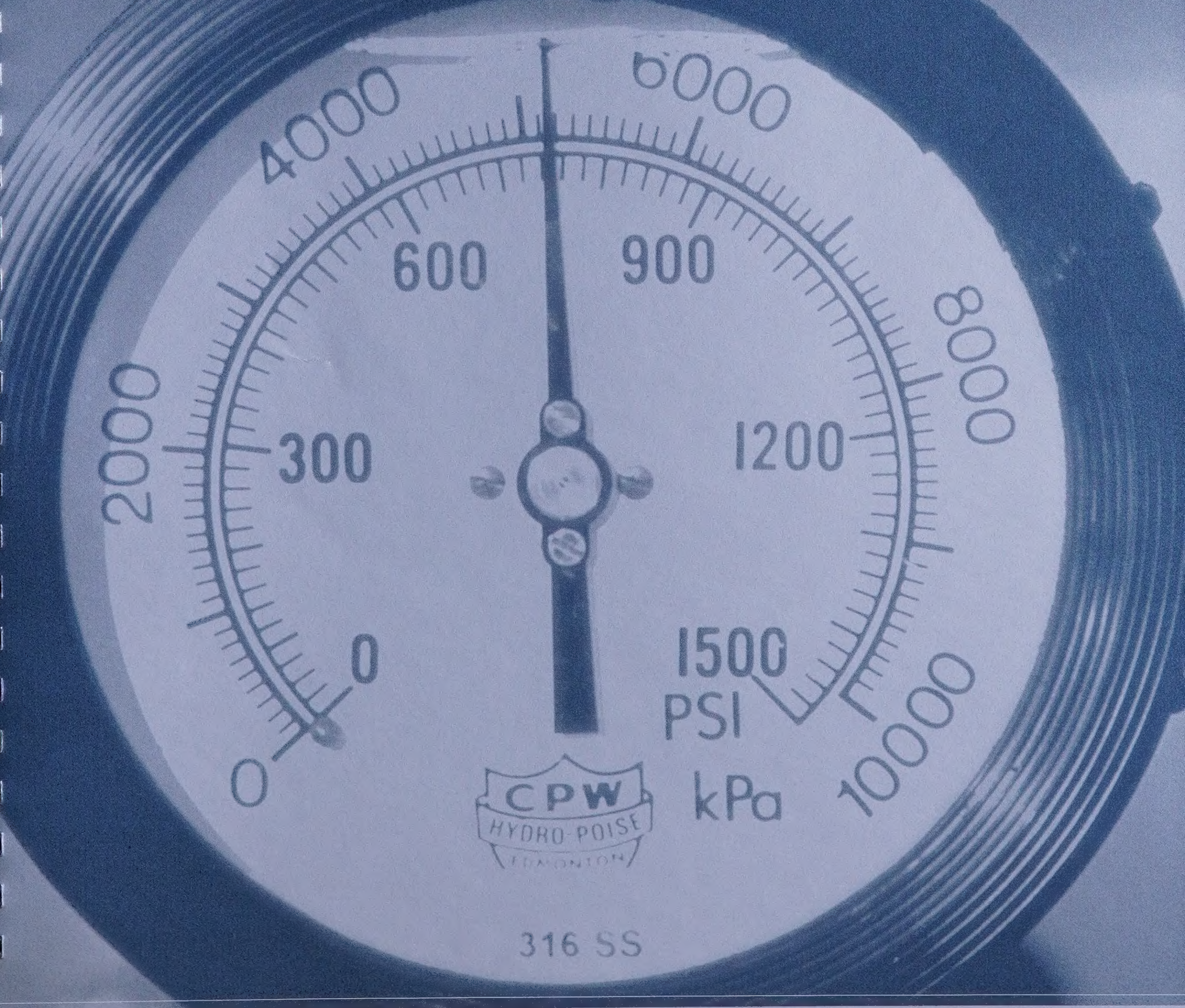
New short-term additions in production will be principally in the Kaybob and Grande Prairie Core Areas. The Kaybob downspacing program will continue with $100 million budgeted to drill 70 wells throughout 2004. Grande Prairie has a budget of $50 million to drill 65 wells, predominantly targeting the repetition of the successful shallow Dunvegan gas play as well as six new deep Wabamun prospects that have been identified. The capital activities at the Liard, Southern and Northwest Core Areas are expected to be sufficient to replace declines through the year.

The current industry environment has commodity prices at historical highs. This has resulted in industry participants generating record levels of cash flow and earnings, leading to the general strengthening of the financial positions of companies in the oil and gas sector. As such there is an abundance of capital available to purchase assets at a time when little is being marketed for sale, thus driving up prices for property acquisitions and, to date, leaving Paramount unwilling to overspend on available acquisition opportunities. Paramount, as a result, has chosen to continue to grow through the drill bit. It is hard to see what will happen in the near future to reverse the supply versus demand imbalance that influences the energy commodities futures market. Until major supply increments can be provided though northern gas development and increased liquefied natural gas capacity, it appears that high natural gas prices are here to stay. Paramount's observation is that there is not a shortage of supply of natural gas in North America, simply a shortage of supply at prices below the current level.

Paramount Resources Ltd., which concurrently raised $5 million on the Alberta Stock Exchange. The same $5 million for those who

Paramount has budgeted a total of $240 million for capital expenditures for 2004 with the expectation that this will allow us to increase production from Q3 2003 exit levels of 130 MMcf/d and 6,000 Bbl/d (28,000 Boe/d) to average 160 MMcf/d and 6,000 Bbl/d (32,500 Boe/d) in 2004 with an even higher year-end exit rate. Cash flow is forecast at around $240 million or approximately $4.00/share, which is essentially equal to the capital expenditure budget. With visible short-term growth, principally at Kaybob and Grande Prairie, combined with an exciting portfolio of long-term prospects, Paramount considers its value creation potential for shareholders to be unparalleled.

James H.T. Riddell
President and Chief Operating Officer



have remained loyal shareholders, of whom there are several, is estimated to exceed half a billion dollars in value. Clay recognized

the hydrocarbon potential of the Devonian in Northeastern Alberta and mapped the subcrop edge of the reservoir within the

Core Producing Areas

Kaybob

Drilling and completion activity continued to increase in the Kaybob Core Area through the year; the highest levels of activity were reached in the fourth quarter, with three drilling rigs and four service rigs active for most of the period. This activity level continued through the first quarter of 2004. Paramount participated in 43 (20.8 net) wells in the fourth quarter bringing the 2003 total to 74 (43.9 net) wells for the year, resulting in 64 (35.9 net) gas wells, eight (8.0 net) oil wells and two (0 net) dry holes. This activity level is up 100 percent from 2002, when Paramount participated in the drilling of 37 (29.76 net) wells. Construction activity also increased through the second half of the year and into the first quarter of 2004. Cold weather at the end of the 2003 suspended some operations, while others took significantly longer to complete. Normal operations did not resume until the end of January, when weather conditions became more seasonal. Total capital expenditures in the Kaybob area in 2003, including facility additions and optimization projects, were $65 million, up from approximately $45 million in 2002.

Gas production in the Kaybob Core Area averaged 79.5 MMcf/d of natural gas, and oil and natural gas liquids production of 2,451 Bbl/d for 2003. Production declines in the first half of the year were a reflection of the limited capital spending in the latter part of 2002 and in the first and second quarters ($21 million) of 2003 as capital was directed to debt reduction. The increase in third and fourth quarter spending ($44 million) is reflected by the production increases in the fourth quarter of 2003 and first quarter of 2004. Year-end exit rates for Kaybob were 90 MMcf/d and 2,400 Bbl/d; rates are expected to increase further in the first quarter of 2004 to 97 MMcf/d. Natural gas production rates are forecast to increase 22 percent in 2004 to an average of 97 MMcf/d (112 TJ/d) and oil and natural gas liquids production is expected to show a modest increase of six percent to average 2,590 Bbl/d for the year.

Paramount continued to take advantage of its existing production and land base in the Kaybob area, by exploiting new reserves in existing fields. Activity in 2004 will be concentrated on the execution of the downspacing program that is more thoroughly described in the areas of interest section of this report. Most of the wells drilled in 2003 in this area were within easy access to existing pipelines and gas plants, thereby reducing finding and development costs. Proved plus probable reserve additions in the Kaybob Core Area using the new National Instrument 51-101 ("NI 51-101") guidelines were 35.4 Bcf and 834 MBbl (6.73 MMBoe), which replaces 2003 production of 29 Bcf and 895 MBbl (5.74 MMBoe). Costs of finding and development for the proved plus probable reserve additions for the Kaybob area were $9.66/Boe in 2003.

Paramount will continue to maximize the operational control of its production by operating wells and production facilities that process the natural gas and liquids. There are currently four Company-operated gas plants in the area that process 64 percent of Paramount's natural gas production. Operations are underway to consolidate two of the Paramount operated gas plants, which should reduce operating costs without sacrificing any processing capacity. The Kaybob North oil battery, completed in 2003, should reduce operating and processing costs related to the oil and condensate in the Kaybob area. Plans are currently being evaluated to use this new battery as a heavy oil blending facility, which would generate additional revenue for Paramount. Regulatory approvals are being sought to expand the Kaybob North oil battery to include water disposal, which should lower operating costs. Additional inlet compression was installed at the Clover plant, adding 5 MMcf/d of additional processing capacity to the plant. Sour gas field compression was added in the Pine Creek area to allow for the production of sour gas that is currently shut in. Paramount has plans to drill three wells in 2004 to take advantage of the additional capacity added with this new compression.

Grande Prairie

This operating area was previously described as the Sturgeon Lake Core Area. Assets related to Sturgeon Lake were sold effective July 1, 2003 for $54.0 million. The Sturgeon Lake property was very mature with high operating costs and proved reserves of 2.7 MMBbl of liquids and 4.2 Bcf gas. Paramount originally purchased the Sturgeon Lake asset in two transactions for approximately $34 million during 2001 and 2002 and estimates that it has recovered virtually all of this in cash flow from the asset. The subsequent sale for $54.0 million represents an excellent return to Paramount on this investment.

For 2003, production averaged 12.4 MMcf/d of natural gas and 1,767 Bbl/d of liquids. The exit rates were 22.4 MMcf/d and 772 Bbl/d. Production rates for gas increased because of the successful capital program, primarily in the Mirage and Saddle Hills fields. The sale of Sturgeon Lake resulted in a decrease in production of 3.0 MMcf/d of natural gas and 1,640 Bbl/d of liquids. In 2003 Paramount drilled 45 gross wells (29.9 net) in the Grande Prairie Core Area. By year end, 12.7 (net) of the new wells were on production. The success ranged from shallow Dunvegan gas wells in Mirage to a deep Wabamun gas well in Saddle Hills. Also in 2003, infrastructure and limited production was added in the Goose, Shadow and Valhalla fields that Paramount plans to exploit with the 2004 capital program.

In Mirage, 17.3 net wells were drilled on this new Dunvegan play. At the end of the year 7.6 MMcf/d was on production from 7.4 net wells with 1.6 wells to be tied in, 0.3 wells to complete and the balance to be evaluated. Up to 40 wells are planned in 2004 to follow up and expand on this play. The successful Saddle Hills Wabamun well was producing at 9 MMcf/d at year end. Paramount plans to follow up with up to six more similar deep wells in 2004.

In 2004, the new Berry Lake field in Northeast Alberta came onstream in March 2004, at 5 MMcf/d. Production rates may increase if capacity in the third-party gas plant is available.

Northwest Alberta

The Northwest Alberta Core Area covers the extreme northwest corner of Alberta, extending into the Cameron Hills in the Northwest Territories. The southern and eastern boundaries are located at township 85, and range 14 west of the fifth meridian, respectively. The Alberta provincial border defines the western edge.

Targeted hydrocarbon-bearing zones in the region start with Pleistocene-aged sands and gravels located at depths of 30 meters through Cretaceous-aged Bluesky/Gething sands, Mississippian carbonates, ending with Middle Devonian carbonates at depths of 1,600 meters. Production facility design and operation in the region accommodates a range of raw production including sweet low-pressure natural gas and high-pressure sour oil and natural gas. Two significant events for Northwest Alberta in 2003 were the completion of the Cameron Hills oil gathering system, battery, and liquid transportation line situated between the Paramount-operated Bistcho Lake facility and the Zama terminal, and the discovery and tie in of Pekisko gas at Haro.

Paramount participated in the drilling of 23 wells, (21.2 net) in the Northwest Alberta Core Area during the 2003 calendar year. The vast majority of field activities relating to seismic acquisition; drilling and construction occurred in the first quarter due to the restricted seasonal access of the area. Annualized 2003 net average production for the region is as follows: natural gas sales 22.3 MMcf/d, crude oil and natural gas liquids 448 Bbl/d. Divestiture of the Pedigree and West Negus properties reduced annual gas production for the region by 5 MMcf/d. An oil gathering line failure in addition to a wax blockage in another pipeline resulted in Paramount realizing only about half of the crude oil production capability of Cameron Hills in 2003.

from depths less than 600 feet and reservoir pressures of just over 100 psi. As the majority shareholder of Paramount Resources Ltd.

The focus of activity for the Northwest Alberta area in 2004 will be at the Cameron Hills and Haro properties; with virtually all of the activity occurring in the first quarter due to the winter-only access nature of the area. Paramount will participate at Haro in the drilling of 12 gas wells (7.5 net), expansion of the existing gas handing capacity from 6 MMcf/d (1.4 MMcf/d net) to 12 MMcf/d (5.9 MMcf/d net). The Cameron oil project is being expanded with the addition of four oil wells (3.5 net) and the facilities necessary to bring those wells on production in 2004. One net gas well will also be drilled at Cameron in the first quarter. The total number of wells that Paramount will be participating in the drilling of in the Northwest Alberta region in 2004 is expected to be 23 (15.5 net).

Liard, NWT/Northeast British Columbia

Natural gas production from this core area averaged 11.6 MMcf/d in 2003. At Maxhamish, the b-83-K/94-O-14 well was tied in and existing producing wells were worked over to maximize performance. At the Chevron-operated Liard Non-Op pool, the 2K-29 location was drilled, completed and placed on production in early May. At Clarke Lake, two locations were drilled with one well at b-57-I/94-J-10 tied in during December.

Exploration activity was dominated by nine locations farmed out to Anadarko at Liard and Arrowhead, NWT. The multi-well program included the drilling of seven Devonian and two Chinkeh locations during the winter of 2003. Two of the Devonian locations did not reach total depth and will finish drilling in 2004. Hydrocarbons discovered as a result of this program have allowed Anadarko to apply to the NEB for six significant discovery licenses to hold expiring lands. Paramount also drilled one unsuccessful Mattson test at K-36 located northeast of Fort Liard.

Looking forward to 2004, development activity will include further drilling at Liard Non-Op and at Clarke Lake as well as recompletion work at Liard/Maxhamish. Exploration will expand into other areas of northeast British Columbia with the drilling of various Cretaceous and Triassic plays as well as deeper Mississippian and Devonian prospects.

Southern Alberta/Southeast Saskatchewan/Montana

The Southern Alberta Core Area is Paramount's most geographically extensive unit, with oil and gas producing in southern Alberta, Saskatchewan, Montana and North Dakota. The Southern Core Area concluded the process of consolidation and focus in late 2003. This process has seen the divestiture of smaller interest and non-operated/non-core properties to pursue the growth of higher interest core properties. The average production for the year was 9.5 MMcf/d of gas, with 2,457 Bbl/d of oil and liquids, giving 4,048 Boe/d including divested properties. At the end of the year, production from this area was 9.8 MMcf/d of natural gas, with 2,018 Bbl/d of oil and liquids, totalling 3,643 Boe/d.

The main activities for 2003 centered in the Chain/Craigmyle area, where seven wells were drilled, 15 recompletions were performed, several compressors were modified and one added, which saw a 30 percent increase in production for the area. This area will also be the focus of activities for the coming year with 17 shallow gas wells planned, and continued modifications to the production systems.

New and reactivated production was also added in Alder Flats (56 percent increase), Enchant (5 percent increase), and Long Coulee (100 percent increase). Late in 2003, two new wells were added at Retlaw, which should result in production increases in the coming year. Enchant, Long Coulee, Sylvan Lake and Retlaw will see further development in 2004. At Paramount-operated oil pools in Rabbit Hills Montana, and Lougheed Saskatchewan new or enhanced waterfloods resulted in production increases of up to 20 percent. Further work is planned on both southeast Saskatchewan and North Dakota oil properties in the coming year.

... investments that allowed NOVA to extend its transportation system in the area in 1982. In the oil

Review of Operations

Paramount production for the year ended December 31, 2003, was 32,630 Boe/d, down 29 percent from 45,898 Boe/d in 2002. This decrease is primarily a result of the disposition of the Northeast Alberta assets to Paramount Energy Trust ("PET" or the "Trust") in the first quarter of 2003, but also includes the effect of other non-core dispositions including the Sturgeon Lake sale throughout the year. Production from the Northeast Alberta assets averaged 97 MMcf/d in 2002 and was included for a small portion of the first quarter of 2003. Natural gas production in 2003 decreased 37 percent from 241.4 MMcf/d in 2002 to 152.8 MMcf/d almost exclusively as a result of the transfer of the northeast assets to PET. Crude oil and natural gas liquid production increased 27 percent to 7,169 Bbl/d from 5,663 Bbl/d in 2002, as the volumes associated with the acquisition of Summit Resources Limited ("Summit") were included for a full year.

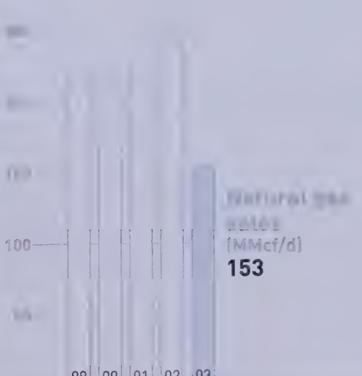
The following table summarizes the average daily production per core area.

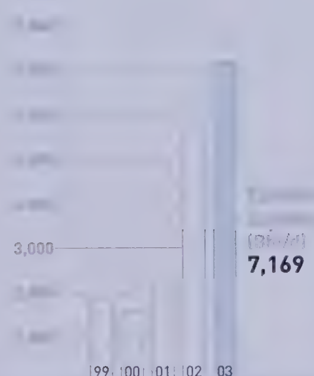
Natural Gas Production (MMcf/d)	**2004e**	**2003**	2002*
Kaybob	**97**	**79.5**	87.5
Grande Prairie	**26**	**12.4**	7.0
Northwest Alberta	**18**	**22.3**	30.4
Liard, NWT/Northeast British Columbia	**9**	**11.6**	12.3
Southern Alberta/Southeast Saskatchewan/Montana/North Dakota	**10**	**9.5**	5.4
Other	**–**	**17.5**	98.8
Total	**160**	**152.8**	241.4

Crude Oil & NGL Production (Bbl/d)			
Kaybob	**2,500**	**2,451**	2,291
Grande Prairie	**650**	**1,767**	1,353
Northwest Alberta	**1,000**	**448**	35
Liard, NWT/Northeast British Columbia	**–**	**9**	15
Southern Alberta/Southeast Saskatchewan/Montana/North Dakota	**1,850**	**2,457**	1,732
Other	**–**	**37**	237
Total	**6,000**	**7,169**	5,663

Total Production (Boe/d)			
Kaybob	**18,667**	**15,704**	16,874
Grande Prairie	**4,983**	**3,831**	2,520
Northwest Alberta	**4,000**	**4,165**	5,102
Liard, NWT/Northeast British Columbia	**1,500**	**1,942**	2,065
Southern Alberta/Southeast Saskatchewan/Montana/North Dakota	**3,517**	**4,048**	2,632
Other	**–**	**2,940**	16,705
Total	**32,667**	**32,630**	45,898

* Six-month production volumes with respect to properties acquired in the Summit acquisition have been averaged over 12 months.





Netbacks for Paramount's production were positively affected by increased pricing in 2003 and offset by increases in per unit royalties, operating costs, general and administrative costs and hedging losses for 2003. Looking forward to 2004, efforts will be made to reduce these per unit costs. Paramount's overall business philosophy is based on a constant focus on economics and return on capital. It is expected that the elimination of some of the higher cost properties through the divestiture process in 2003 will allow the Company to see a decrease in per unit costs in 2004, even with the general expectation for the costs of services to increase in the current industry environment.

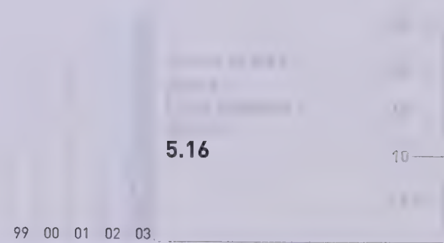
Overall natural gas supply declines in North America coupled with stronger natural gas demand resulted in an increase of 70 percent in Paramount's average natural gas sales price before hedging to $5.99/Mcf as compared to $3.53/Mcf in 2002. These higher natural gas prices were offset by $53.2 million commodity hedging losses incurred during 2003, attributable primarily to natural gas hedges. These hedges were initiated in order to reduce cash flow risk with respect to the Summit acquisition as the bridge loan used to finance the acquisition was extended due to unexpected delays in closing the Trust disposition. Paramount's average natural gas price after hedging was $5.16/Mcf as compared to $4.08/Mcf in 2002. Oil and natural gas liquids ("NGL") prices before hedging averaged $38.27/Bbl in 2003, as compared to $35.20/Bbl in 2002.

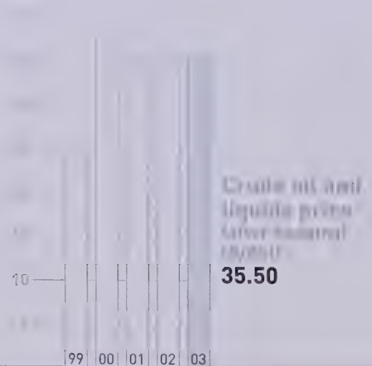
Although Paramount's total operating costs decreased 6 percent to $81.2 million in 2003 as compared to $86.1 million in 2002, costs on a unit-of-production basis increased 33 percent to $6.82/Boe from $5.14/Boe in 2002. The costs of services appear to be higher industry wide as activity levels are at all time highs. Paramount expects that its costs on a per unit basis will be reduced as more production is put through existing facilities and higher per unit properties such as Sturgeon Lake have been eliminated through the Company's disposition activities in 2003

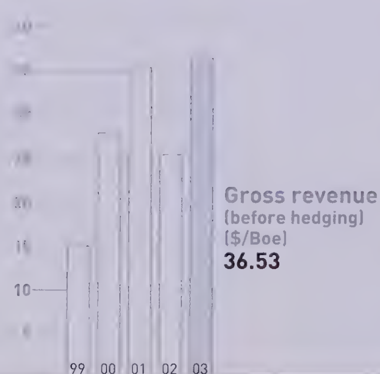
Royalties increased 11 percent to $82.5 million in 2003 from $74.4 million in 2002, primarily as a result of higher natural gas prices. Paramount's corporate royalty rate remained virtually unchanged in 2003, 19.0 percent as opposed to the 19.4 percent paid in 2002.

General and administrative costs in 2003 increased 23 percent to $19.9 million, up from $16.2 million in 2002. The Company had increased head office staffing levels during 2003 in order to identify and develop new reserves within its core areas, as well as advance its long-term projects such as Colville Lake and Northeast Alberta bitumen.

Paramount's Cash Flow From Operations decreased 36 percent to $167.3 million in 2003 from $259.9 million in 2002. The disposition of assets to the Trust and commodity hedging losses of $53 million offset significantly higher commodity prices. Lower production levels due to the Company's property rationalization program in 2003 also decreased production and hence cash flow. A one-time gain on the sale of investments was also included in the 2002 results.







Cash Flow Reconciliation	2003		2002	
Volume (Boe)[1]	($/Million)	$/Boe	($/million)	$/Boe
Gross revenue[2]	**436.1**	**36.61**	386.3	23.06
Gain on sale of investments	**(1.0)**	**(0.08)**	40.8	2.44
Royalties (net of ARTC)	**(82.5)**	**(6.93)**	(74.4)	(4.44)
Operating costs	**(81.2)**	**(6.82)**	(86.1)	(5.14)
Operating netback	**271.4**	**22.78**	266.6	15.92
Commodity hedging	**(53.2)**	**(4.47)**	46.8	2.79
G&A	**(19.9)**	**(1.67)**	(16.2)	(0.97)
Non-cash G&A	**1.2**	**0.10**	0.3	0.02
Bad debt expense	**(6.0)**	**(0.50)**	–	–
Interest on long-term debt	**(19.9)**	**(1.67)**	(23.9)	(1.43)
Non-cash interest	**0.2**	**0.01**	–	–
Lease rentals	**(3.6)**	**(0.30)**	(4.5)	(0.27)
Large Corporation/current taxes	**(2.9)**	**(0.24)**	(9.2)	(0.55)
Cash flow	**167.3**	**14.04**	259.9	15.51
Weighted average shares (millions)	**60.1**		59.9	
Cash flow per basic share ($/share)	**2.78**		4.37	

(1) Barrels of oil equivalent calculated on the basis of 1 barrel = 6 Mcf.

(2) Gross revenue included petroleum and natural gas revenue and other.

Net Capital Expenditures

Net capital expenditures amounted to a net recovery of $145.0 million in 2003 as compared to expenditures of $494.5 million in 2002. The Company disposed of a number of properties during 2003, including the Trust assets, resulting in a net capital recovery for the year.

Capital Expenditures (thousands of dollars)	2003	2002
Land	**$ 22,288**	$ 6,410
Geological and geophysical	**8,450**	9,303
Drilling	**123,455**	124,076
Production equipment and facilities	**69,560**	77,407
Exploration and development expenditures	**223,753**	217,196
Summit Resources Limited acquisition	**–**	251,422
Property acquisitions	**937**	28,610
Proceeds received on property dispositions	**(371,601)**	(5,042)
Other	**1,933**	2,349
Net capital expenditures	**$ (144,978)**	$ 494,535

... Although the first well

Land

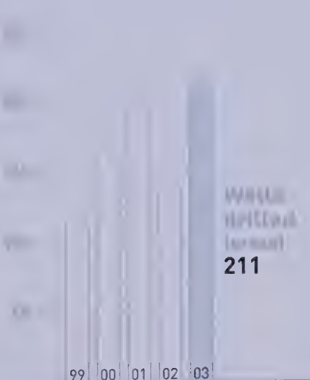
Paramount's undeveloped land inventory was reduced principally as a result of dispositions. The majority of this reduction came as a result of the transfer of assets to PET. Paramount spent $22.3 million in 2003 on purchases of additional undeveloped land.

Land (thousand acres)	**2003**			2002		
	Gross	**Net**	**Average Working Interest**	Gross	Net	Average Working Interest
Land assigned reserves	**981**	**586**	**60%**	2,169	1,532	71%
Undeveloped land	**4,756**	**2,800**	**59%**	5,506	3,545	64%
Total	**5,737**	**3,386**		7,675	5,077	
Fair market value of undeveloped land ($ millions)		**$ 98.2**			$ 117.3	

Drilling

Paramount participated in the drilling of 211 (138.9 net) wells in 2003 with a success rate of 93 percent. A total of 180 (120.7 net) gas wells, 16 (12.4 net) oil wells and 15 (5.8 net) dry and abandoned wells were drilled. Kaybob Core Area had the highest number of locations with the drilling of 74 (43.9 net) wells. An active drilling program was also completed in the Grande Prairie Core Area as well with the drilling of 45 (29.9 net) wells.

Drilling Results	**2003**		2002	
	Gross	**Net**	Gross	Net
Exploratory				
Gas	**45**	**30.7**	38	27.4
Oil	**3**	**2.1**	4	3.6
D&A	**8**	**2.2**	4	4.0
Total exploratory	**56**	**35.0**	46	35.0
Success rate (gross)	**86%**		91%	
Development				
Gas	**135**	**90.0**	76	56.3
Oil	**13**	**10.3**	5	31
SWD	**-**	**-**	1	10
D&A	**7**	**3.6**	7	4.0
Total development	**155**	**103.9**	89	64.5
Success rate (gross)	**95%**		92%	
Total wells drilled	**211**	**138.9**	135	99.4
Success rate (gross)	**93%**		92%	

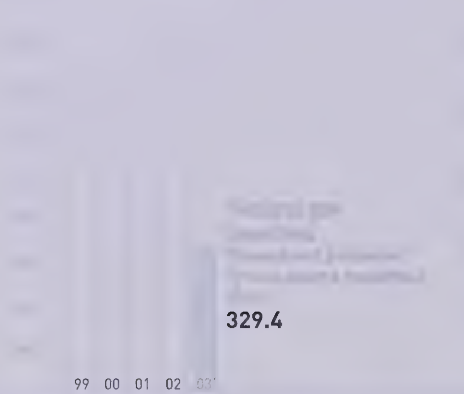


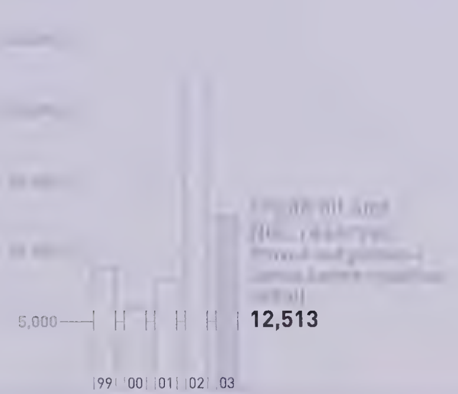
Paramount's reserves for the year-ended December 31, 2003, were evaluated by McDaniel and Associates Consultants Ltd. ("McDaniel"). They have evaluated Paramount's reserves for the entire 25-year existence of the Company. Commencing with the most recent year-ended 2003, Paramount's reserves have been calculated in compliance with the new NI 51-101. The new reserve disclosure standards related to NI 51-101 require a higher standard of confidence in reserve volumes within the individual reserve reporting categories. In particular, proved reserves are now defined as having a 90 percent probability that these reserves will be recovered, and probable reserves are now risked at a 50 percent probability that these reserves will be recovered. Comparisons of year-ended 2003 reserves are best made to prior year established reserves (proved plus half probable) although this does not fully recognize the move to more conservative reporting standards. As such, Paramount estimates that the effects of the reserve revisions associated with NI 51-101 are five percent for proved reserves at the beginning of the year, excluding the Trust.

The following table summarizes the reserves for the year-ended December 31, 2003, using forecast prices and costs.

Proved and Probable Reserves Net Present Value	**Proved and Probable Reserves**				**Net Present Value** ($millions)		
	Natural Gas	**Crude Oil**	**Natural Gas Liquids**	**Boe**	**Discount Rate Before Tax**		
Reserve category	(Bcf)	(MBbl)	(MBbl)	(MBoe)	0%	5%	10%
Canada							
Proved							
Producing	174.9	3,755	3,269	36,174	636.9	545.8	483.0
Non-producing	47.6	529	543	9,004	140.1	101.7	79.9
Undeveloped	18.6	437	111	3,648	59.2	34.7	22.6
Total proved	241.1	4,721	3,923	48,827	836.2	682.2	585.5
Probable	87.7	1,271	479	16,367	267.9	184.9	135.2
Total proved plus probable Canada	**328.8**	**5,992**	**4,402**	**65,194**	**1,104.1**	**867.1**	**720.7**
United States							
Proved							
Producing	0.5	1,971	2	2,056	15.7	13.7	12.2
Non-producing	–	–	–	–	(0.3)	(0.3)	(0.3)
Undeveloped	–	–	–	–	–	–	–
Total proved	0.5	1,971	2	2,056	15.4	13.4	11.9
Probable	0.1	143	3	163	1.6	1.3	1.0
Total proved plus probable US	0.6	2,114	5	2,219	17.0	14.7	12.9
Total Company							
Total proved	241.7	6,692	3,925	50,883	851.6	695.6	597.4
Total probable	87.7	1,414	482	16,530	269.5	186.2	136.2
Total reserves	**329.4**	**8,106**	**4,407**	**67,413**	**1,121.1**	**881.8**	**733.6**

(Columns may not add due to rounding)





Reserve Reconciliation for Year-end 2003

Paramount's reserves reflected the dispositions of virtually all of Paramount's assets in Northeast Alberta to the Trust, the Sturgeon Lake assets and additional minor non-core assets all of which occurred during 2003. As well, Paramount's reserve disclosure for the year-ended 2003 is now evaluated using the newly implemented standards of disclosure defined by NI 51-101. Total proved reserves at year end 2003 stood approximately 242 Bcf and 10.6 MMBbl or 50.9 MMBoe and proved plus probable reserves stood at 329 Bcf and 12.5 MMBbl or 67.4 MMBoe.

The following table sets forth the reconciliation of Paramount's gross reserves for the year-ended December 31, 2003, as evaluated by McDaniel using forecast prices. We have reconciled our reserves to January 1, 2003, proved plus 50 percent of probable reserves (Established reserves). Gross reserves include working interest reserves before royalties.

	Proved Reserves			**Probable Reserves**			**Proved Plus Probable Reserves**		
	Gas	**Oil & NGL**	**Boe**	**Gas**	**Oil & NGL**	**Boe**	**Gas**	**Oil & NGL**	**Boe**
	(Bcf)	(MBbl)	(MBoe)	(Bcf)	(MBbl)	(MBoe)	(Bcf)	(MBbl)	(MBoe)
Paramount Resources Ltd.									
Jan. 1, 2003 (excluding Trust)	**282.3**	**17,545**	**64,595**	**66.4**	**2,650**	**13,717**	**348.7**	**20,195**	**78,312**
Paramount Energy Trust									
Jan. 1, 2003	164.3	–	27,367	19.7	–	3,283	183.9	–	30,650
Total reserves Jan. 1, 2003[1]	**446.5**	**17,545**	**91,961**	**86.1**	**2,650**	**17,000**	**532.6**	**20,195**	**108,962**
Divestments									
Paramount Energy Trust	158.4	–	26,400	19.7	–	3,283	178.1	–	29,683
Sturgeon Lake	3.4	2,147	2,714	0.6	347	447	4.0	2,494	3,161
Minor divestments	12.8	2,462	4,595	2.0	225	558	14.8	2,687	5,153
Total 2003 divestments[2]	**(174.6)**	**(4,609)**	**(33,709)**	**(22.3)**	**(572)**	**(4,288)**	**(196.9)**	**(5,181)**	**(37,997)**
Total 2003 acquisitions	**1.6**	**–**	**267**	**0.1**	**–**	**17**	**1.7**	**–**	**284**
2003 Capital program additions	**52.3**	**1,428**	**10,145**	**11.2**	**251**	**2,118**	**63.5**	**1,679**	**12,263**
Total 2003 production	**(55.8)**	**(2,617)**	**(11,917)**	**–**	**–**	**–**	**(55.8)**	**(2,617)**	**(11,917)**
Technical revisions[3]	(10.4)	(937)	(2,670)	12.6	(433)	1,667	2.2	(1,370)	(1,003)
Revisions due to NI 51-101[4]	(17.9)	(193)	(3,176)	–	–	–	(17.9)	(193)	(3,176)
Total revisions	**(28.3)**	**(1,130)**	**(5,847)**	**12.6**	**(433)**	**1,667**	**(15.7)**	**(1,563)**	**(4,180)**
Total reserves Jan. 1, 2004	**241.7**	**10,617**	**50,900**	**87.7**	**1,896**	**16,513**	**329.4**	**12,513**	**67,413**

(Columns may not add due to rounding)

(1) January 1, 2003 reserves are proved plus half probable.

(2) Total 2003 divestitures net of reported production in 2003.

(3) Paramount estimates of conventional technical revisions.

(4) Paramount estimates of revisions due to NI 51-101.

Paramount has calculated the capital associated with the 2003 reserve additions and as such has excluded two separate expenditures. The first is the $23.3 million of expenditures associated with properties which were disposed during the year. Capital expenditures in this category were almost entirely related to the Ells property and the Sturgeon Lake property, which were both sold during the year. The other capital excluded from the finding and development cost calculation was $5.8 million associated with the exploration at Colville Lake. This capital will be included in the finding and development calculation during the year in which reserves are first booked for Colville Lake by the Company. In addition, capital was reduced by $5.0 million to reflect the net increase in the value of our undeveloped acreage inventory, net of the Trust disposition. Future capital of $2.4 million to fully develop the booked proved reserves, and $3.3 million to fully develop the booked proved and probable reserves, were included in the finding and development calculation. Paramount's finding and development costs for new reserve additions were calculated to be $18.93/Boe for proved reserves and $15.73/Boe for proved plus probable reserves. Finding and development costs at Kaybob in 2003 of $9.66/Boe were in line with expectations. Paramount has allocated approximately 50 percent of its 2004 capital budget to a continuation of the downspacing program in the Kaybob area and will positively influence Paramount's 2004 finding and development costs.

FINDING AND DEVELOPMENT CAPITAL

2003 Working Interest Capital Expenditures		Future Capital New Additions		Total F&D Capital	
($ millions)	2003 Capital	Proved	Proved Plus Probable	Proved	Proved Plus Probable
Land	22.3	–	–	22.3	22.3
Seismic	8.4	–	–	8.4	8.4
Exploration and development	123.4	0.4	0.7	123.8	124.1
Facilities	69.6	2.0	2.6	71.6	72.2
Total net capital expenditures	223.7	2.4	3.3	226.1	227.0
Less increase in value of undeveloped land	(5.0)	–	–	(5.0)	(5.0)
Less 2003 Colville expenditures	(5.8)	–	–	(5.8)	(5.8)
Less 2003 disposition properties	(23.3)	–	–	(23.3)	(23.3)
2003 F&D net capital expenditures	**189.6**	**2.4**	**3.3**	**192.0**	**192.9**

FINDING AND DEVELOPMENT COSTS

Paramount's finding and development costs for new reserve additions were calculated to be $18.93/Boe for proved reserves and $15.73/Boe for proved plus probable reserves.

	Proved Capital ($MM)	Proved Reserves (MBoe)	Proved F&D ($/Boe)	Proved Plus Probable Capital ($MM)	Proved Plus Probable Reserves (MBoe)	Proved Plus Probable F&D ($/Boe)
F&D Cost						
Extensions and discoveries	192.0	10,145	18.93	192.9	12,262	15.73

Drilling and completion
Geological and geophysical
Plant gathering & equipment
Land purchases

Net Asset Value ($ millions as at December 31, 2003)		**2003**		2002
Present value of appraised reserves [1][2]	**$**	**733.6**	$	1,123.7
Value of short-term investments		**17.3**		14.2
Appraised value of undeveloped land		**98.2**		117.3
Seismic (at cost)		**37.6**		34.3
Projects under evaluation (at cost)		**42.1**		100.0
Building (at cost)		**8.5**		8.5
Other		**10.6**		12
Total assets		**947.9**		1,410.0
Bank loans		**60.4**		494.8
Senior notes		**226.9**		–
Shareholder loan		**–**		33.0
Working capital deficiency		**25.7**		30.1
Drilling rig indebtedness		**4.6**		4.5
Mortgage		**6.7**		7.0
Total liabilities		**324.3**		569.4
Net asset value	**$**	**623.6**	$	840.6
Net asset value per basic common share	**$**	**10.38**	$	14.14

(1) Proved plus probable reserves discounted at 10 percent before income tax used for 2003.

(2) Proved plus half probable reserves discounted at 10 percent before income tax used for 2002.

(3) Outstanding shares: 2003 – 60,094,600 (2002 – 59,458,600).

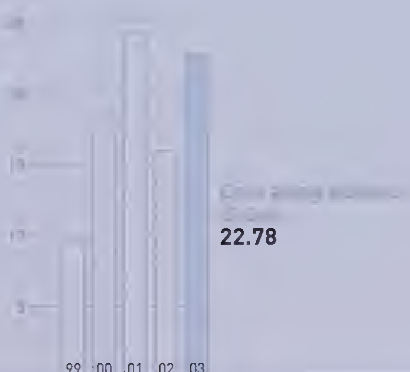
NOTES TO NET ASSET VALUE

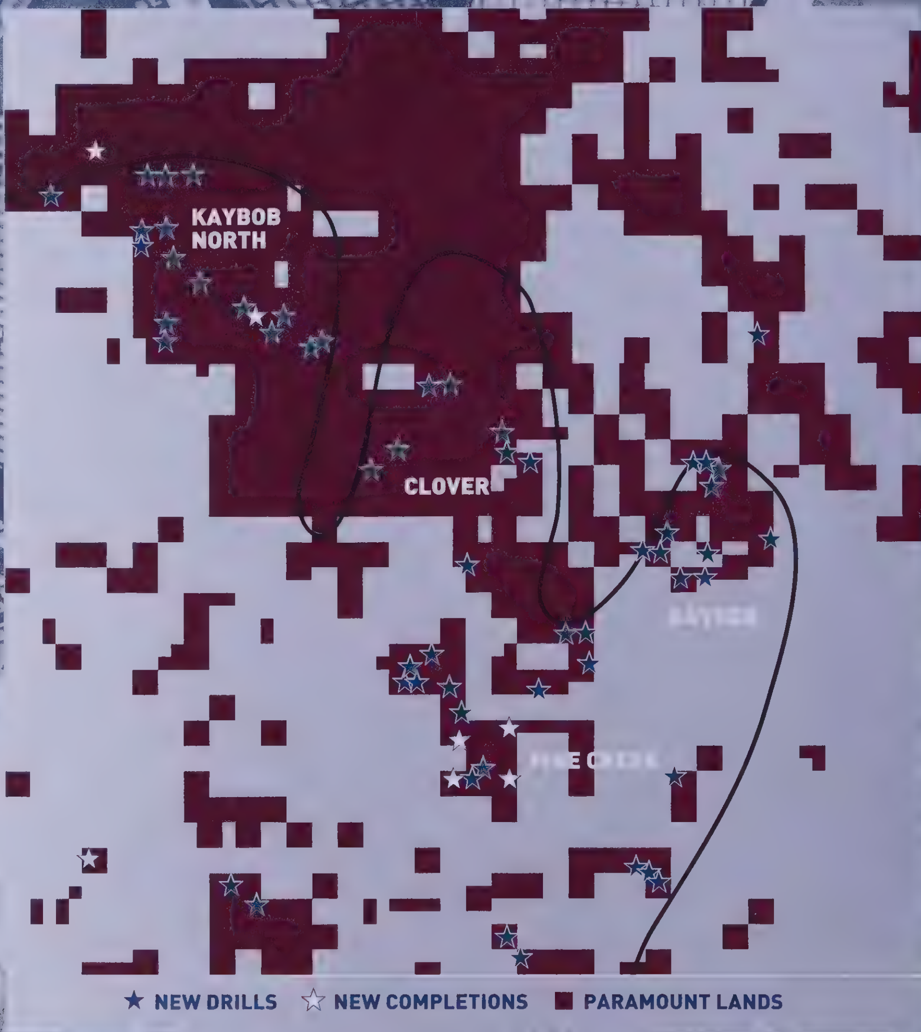
i) Reserve values were determined by McDaniel as at December 31, 2003, using their forecast prices and costs case.

ii) No value has been assigned to tangible assets other than those associated with proved producing reserves.

iii) Paramount's hedging activities, which extend past December 31, 2003, have not been valued by McDaniel.

iv) Reserve values have been evaluated under a blow-down scenario.




KAYBOB
NORTH
CLOVER
NEW DRILLS
NEW COMPLETIONS
PARAMOUNT LANDS

Areas of Interest Kaybob Downspacing Program

The Kaybob area is known for its multizone producing potential. Geological formations range from the shallow Belly River at 500 meters to the Swan Hills at depths greater than 3,500 meters and provide attractive drilling opportunities. Most of the early drilling in the area focused on the huge oil and gas potential of the deep Devonian carbonates. Paramount's focus has been primarily on the shallower formations that had not been fully exploited by previous operators in this area. A considerable amount of time has been spent evaluating the Lower Cretaceous-aged Gething formation and acquiring acreage with exploitation opportunities in this zone.

The Gething formation was deposited in a widespread fluvial to estuarine environment. Numerous fluvial channel sands were deposited in large valleys; these channel sands represent the target of Paramount's down spacing program. The Gething formation in this geographic area lies along the up-dip boundary of the deep basin hydrologic environment; the Gething reservoir sands are gas-saturated and slightly under pressured relative to the water pressure gradient. The sands can be subdivided into upper, middle and lower channels, individual Gething channel sands can be up to 15 meters thick and stacked channels can be up to 30 meters thick. Mapping Gething channels can be extremely difficult. High quality seismic can be integrated to assist in mapping channels trends and identify areas were multiple channels may be drilled.

Previously, the Gething formation was exploited by drilling one well per section (one square mile), as per standard Alberta gas well spacing. Through integration of geological and geophysical mapping and engineering decline analysis, it became apparent that only a fraction of the original gas in place would be recovered. Original Gething gas reserves can be in excess of 15 Bcf per section, however a typical Gething well may only produce 2-5 Bcf. Therefore, to effectively drain the reservoir, more than one well per section was going to be required to deplete all of the gas reserves. Permeability barriers between different sands in the same channel, as well as permeability boundaries along channel margins affect productivity and ultimate reserve recovery. The amalgamation of Gething sands and channels results in a complex reservoir development. To reduce risks, such as penetrating reservoir quality sand and depleted reservoirs, a thorough geological model must be used to find new gas pools in existing gas fields.

To produce more than one well per section from the same formation, an application must be made to the Alberta Energy and Utility Board providing the technical discussion justifying a change in the well spacing and thus requesting permission to reduce the spacing unit to more than one well per section. Paramount and its partners were applying for reduced spacing approvals in the first half of 2003, most approvals were given in the second half which allowed Paramount to proceed with its aggressive drilling program. Paramount participated in approximately 50 wells in the Kaybob area that were specifically drilled to exploit additional Gething gas reserves in 2003. Paramount is continuing to make applications to reduce well spacing in the remaining Gething gas pools and is also evaluating the potential to reduce the well spacing in other low permeability reservoirs.

Paramount will continue to take advantage of the existing production and land base in the Kaybob area, by exploiting new reserves in existing fields. Most of the wells drilled in this area were able to access existing pipelines and gas plants, there by reducing the cost of finding and development. Paramount plans to drill another 50 wells in 2004 that exploit additional reserves in the Gething.


7-36 Dunvegan
Discovery well
4-35 Wabamun Discovery Well
NEW DRILLS
PARAMOUNT LANDS

Areas of Interest Grande Prairie

Accessible infrastructure, multizone reservoir potential, abundant crown and proprietary Paramount land are the key advantages offered to the Company in this ever expanding core growth area. 2003 was a year of rapid expansion of Paramount's opportunities at Grande Prairie. The highlights in 2003 were the successful drilling of a deep Wabamun prospect, as well as the drilling and expansion of the shallow gas Dunvegan reservoirs in the Mirage area. Paramount added 14 MMcf/d of new production in 2003 from these two properties. An aggressive drilling and infrastructure program in 2004 aims to improve on these results significantly, as well as lowering finding and development, and operating costs. Having a substantial seismic database as well as having access to a large volume of inexpensive trade seismic positively impact Paramount's finding and development cost, as well as risk profile.

MIRAGE – SHALLOW DUNVEGAN PROJECT

This project's nucleus is the Mirage field, which was acquired by Paramount through the acquisition of Summit in 2002. The existence of a contiguous landbase and extensive infrastructure in the immediate area demanded further geological investigation of shallower zones that had been bypassed. A key farmout to another operator in the area, on a relatively risky shallow gas prospect, resulted in two economically successful wells. This drilling, at no risk to the Company, validated Paramount's exploratory concept for shallow gas in the immediate area.

Since drilling, completion and tie in costs are relatively low on these shallow gas opportunities, Paramount elected to drill or participate in a total of 21 wells, and retains a significant working interest in the two other farm-out wells. With the success of the exploratory program, the expansion of infrastructure, compression was deemed to be a priority. One new facility comprised of a single compressor was added at Mirage in the fourth quarter of 2003. A second compressor was added at the same facility in the first quarter of 2004, and a third 5 MMcf/d unit is now planned for the second quarter of 2004. In addition, looping of pipelines between various Paramount-operated facilities will allow for optimal production balancing, and will allow the Company to tie in other operators' production on a fee based, best efforts basis.

In the foreseeable future, the Company plans to capitalize on its shallow gas expertise by aggressively expanding shallow gas opportunities in the Grande Prairie Core Area, which also includes a portion of Northeastern British Columbia.

SADDLE HILLS – DEEP DEVONIAN PROJECT

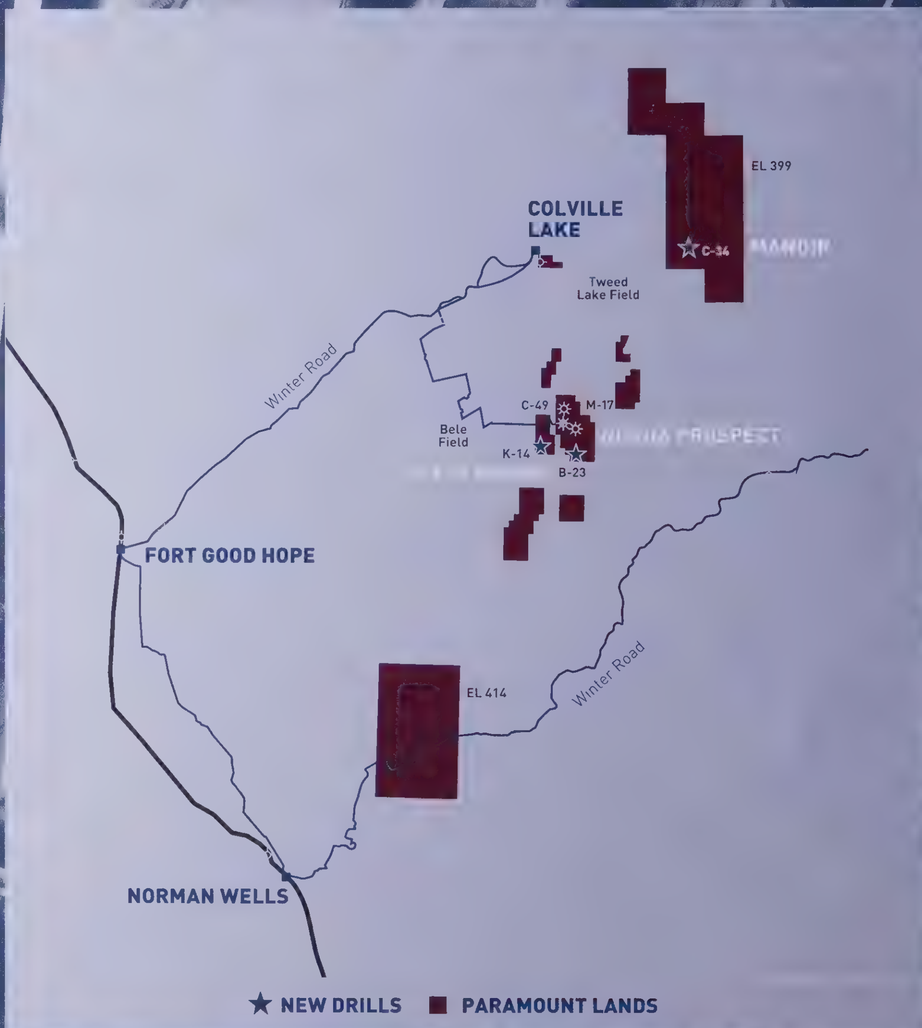
Early in 2003, Paramount initiated its deep Devonian program in the Saddle Hills area, capitalizing on the success of a senior E&P company in the immediate area. Paramount's land position in this area is a result of a timely acquisition of production and undeveloped land that occurred in late 2001. Currently Paramount has drilled two wells on this play, with one producing, and the other requiring further completion.

The target reservoir for the deep Devonian project is the Wabamun formation. This reservoir is characterized by the occurrence of a porous, fractured, hydrothermal dolomite in a dominantly tight limestone host rock. Hydrothermal dolomite is primarily related to hot magnesium rich fluids percolating upward through deep crustal faults and modifying the host rocks, in this case the thick Wabamun section.

In this play type, 3D seismic is considered to be key in mapping the faults and identifying the dolomite reservoirs. Paramount was able to access a low cost high quality 3D seismic database that covers not only the immediate area surrounding the Company's 4-35-75-7W6 discovery well, but also a large portion of the Grande Prairie area. Consequently the Company is pursuing opportunities similar to 4-35, and it's unique structural setting, along the Saddle Hills fault system as well as in other areas to the west.

While risk, from a cost, operational and technical point of view is higher on the deep play, the reward is significant with test rates in excess of 15 MMcf/d of natural gas and 300 Bbl/d of natural gas liquids. Average production rates of 9 MMcf/d of natural gas and 300 Bbl/d of natural gas liquids have been established over the first three months from the 4-35 well.

In summary, the Grande Prairie Core Area represents good growth potential for Paramount, with a balanced portfolio of deep and shallow plays. The presence of infrastructure, large land position, and multizone reservoirs should ensure that Grande Prairie is an area that provides solid future growth in production and cash flow for the Company and its shareholders.



Clay is extremely proud of the achievements of the team at Paramount over the last

Areas of Interest Colville Lake, Northwest Territories

The Colville Lake project area is situated at the Arctic Circle, 1,850 km north of Calgary, within the Sahtu settlement region. The area was recognized by Paramount as having significant potential for large-scale structurally and stratigraphically trapped sweet liquid-rich gas reserves within Cambrian-aged Mt. Clark sandstones and overlying Mt. Cap sandstones, siltstones and dolomites. The NEB estimates that over 400 Bcf has been found in previous discoveries drilled in this area in the 1970s and early 1980s. Paramount's Colville Lake acreage is proximal to the proposed Mackenzie Valley Pipeline that will bring gas out of the Mackenzie Delta and Beaufort Sea to southern markets. Paramount, with its 50 percent partner Apache Canada Ltd., has a significant land base of some 650,000 acres (approximately 28 Alberta townships) in the Colville area. This land position was put together in 2000/2001 through the acquisition of a concession agreement with the local First Nations people and through the purchase of two Federal Exploration Licenses ("EL 399 and EL 414").

In early 2003, the partners drilled two 1,450-meter gas wells on the Nogha prospect located on the concession lands. The first well in the drilling program, Apache Paramount Nogha C-49, was cased and completed as a successful Mt. Clarke gas well. The second well, Paramount Apache Nogha M-17, was drilled down-structure from the C-49 well and was cased and completed as a second successful Mt Clark gas well. The results of the flow and buildup data from these initial wells are viewed by the partners as extremely encouraging. New 2D seismic was shot in early 2003 to evaluate the EL 399 license and heli-portable 2D data was acquired later in the summer over the EL 414 license.

For the upcoming 2004 winter season, additional completion work is planned for the existing Nogha wells including stimulation and flow testing of the previously drilled Nogha M-17 well. Two drilling rigs will be utilized to drill up to four delineation and exploratory wells in the Colville area. The Nogha B-23 well has been successfully drilled and cased, further delineating the Nogha discovery and our understanding of the geology of the prospect. Further north, the Manoir Ridge C-34 well has been successfully drilled and cased as a potential New Pool Discovery. As well, further west, the West Nogha prospect has been tested and the K-14 well has been successfully drilled and cased as a potential New Pool Discovery. At the time of writing, all three of the wells drilled in the 2004 winter program are undergoing completion operations.

Success to date from exploration drilling at Colville Lake is now leading to the evaluation of several development scenarios including the participation in the Mackenzie Valley Pipeline or possibly the construction of a dedicated pipeline to be built approximately 500 miles in length from Norman Wells south into Alberta to tie in to the existing pipeline infrastructure.

Management's Discussion & Analysis (MD&A)

l to report its financial and operating results for the year ended

should be read in conjunction with the consolidated financial
e consolidated financial statements have been prepared in
ccounting principles ("GAAP"). A reconciliation to United States

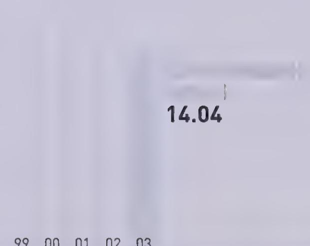
able securities laws. Forward-looking statements
ice or other statements that are not statements of fact.
: to, among other things: Paramount's business strategy,
:ing of Paramount's production toward natural gas,
n costs, the size of available income tax pools, the renewal of
l expenditure program, cash flow estimates, environmental
nmodity prices, and the impact of the adoption of
Accounting Guidelines.

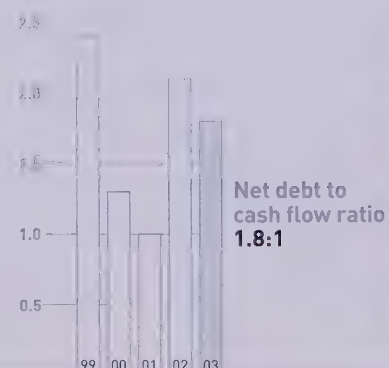
looking statements are reasonable, undue reliance
: such expectations will prove to have been correct.
s not to be correct, including known and unknown risks and
but are not limited to: crude oil and natural gas price volatility,
d supplies, market competition, uncertainties in the estimates
the timing of achieving such levels, the Company's ability
acy of funding for capital investments, future growth prospects and
he cost of future dismantlement and site restoration, the Company's
e adequate product transportation, changes in environmental and
ing basis, and general economic conditions. The Company's
r this cautionary statement. We undertake no obligation to

s of oil equivalent (Boe) on the basis of six thousand cubic feet
n isolation. A Boe conversion ratio of 6 Mcf = 1 Bbl is based on an
equivalency at the well head.

al Information Form, can be found on the SEDAR website at www.sedar.com.

Paramount is an exploration, development and production company with established operations in Alberta, British Columbia, Saskatchewan, the Northwest Territories, Montana, North Dakota and California. Management's strategy is to maintain a balanced portfolio of opportunities, to grow reserves and production in the Company's core areas while maintaining a large inventory of undeveloped acreage, to focus on natural gas as a commodity, and to selectively enter into joint venture agreements for high risk/high return prospects.





CREATION OF PARAMOUNT ENERGY TRUST (THE "TRUST")

In 2002, the Company announced its intention to create an independent energy trust, providing shareholders with an investment which would complement Paramount's historical exploration and development strategy.

(a) On February 3, 2003, Paramount transferred to the Trust assets in the Legend area of Northeast Alberta for net proceeds of $28 million, which was paid to Paramount on March 11, 2003, and 9,907,767 units of the Trust.

(b) On February 3, 2003, Paramount declared a dividend-in-kind of an aggregate of 9,907,767 units of the Trust. The dividend was paid to holders of Paramount common shares of record on the close of business on February 11, 2003. The dividend was declared after the Trust received all regulatory clearances with respect to its final prospectus in Canada and its registration statement in the United States. The final prospectus and registration statement qualified and registered (i) the dividend trust units, (ii) rights to purchase further trust units, which rights were issued to unitholders after the payment of the dividend, and (iii) the trust units issuable upon the exercise of the rights.

(c) On March 11, 2003, in conjunction with the closing of a rights offering by the Trust, Paramount disposed of additional assets in Northeast Alberta to Paramount Operating Trust for total consideration of $167 million, including adjustments to the purchase price. The combined production of natural gas including the assets in the Legend area averaged 97 MMcf/d during 2002.

The closing of the above transactions in the first quarter of 2003 represent the completion of the formation and structuring of Paramount Energy Trust.

DISPOSITION OF THE STURGEON LAKE PROPERTY

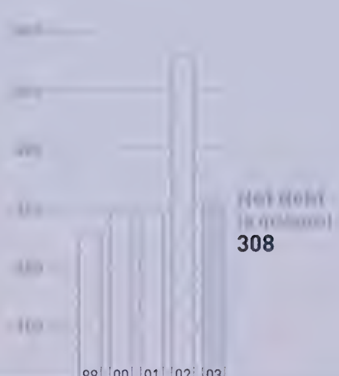
On October 1, 2003, Paramount sold its interest in the Sturgeon Lake property, including the associated oil batteries and gas plants, for total consideration of $54.0 million. Production from the Sturgeon Lake assets averaged 1,640 Bbl/d of oil and natural gas liquids and 2,965 Mcf/d of natural gas for the nine months ended September 30, 2003. A pre-tax gain on sale of property and equipment of $18.7 million was recorded on the disposition.

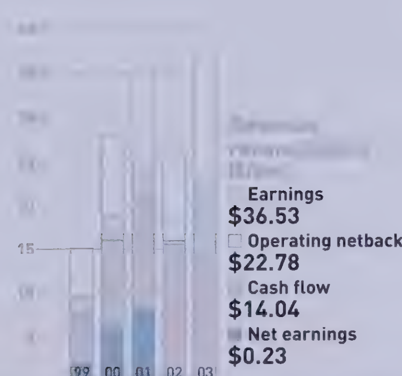
ISSUANCE OF US $175 MILLION OF MEDIUM-TERM SENIOR NOTES

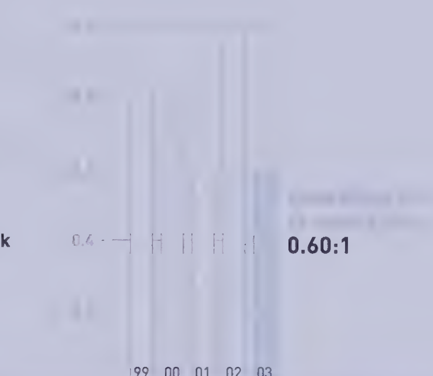
On October 27, 2003, the Company closed an offering of US $175 million in senior unsecured notes. The notes bear interest at 7 7/8 percent, and mature on October 27, 2010. The offering allowed Paramount to diversify its sources of financing and expand its financial flexibility.

SALE OF NON-CORE PROPERTIES

During 2003, the Company successfully executed a disposition program consisting of minor, non-core producing and non-producing properties for total consideration of $71.2 million.







Revenue (thousands of dollars)	**2003**	2002	2001
Natural gas	**$ 333,924**	$ 311,438	$ 481,436
Oil and natural gas liquids	**100,135**	72,750	28,442
Petroleum and natural gas revenue	**434,059**	384,188	509,878
Commodity hedging gain (loss)	**(53,204)**	46,813	15,808
Gain (loss) on investments	**(1,020)**	40,830	2,982
Other	**2,012**	2,111	(295)
Gross revenue	**$ 381,847**	$ 473,942	$ 528,373

Petroleum and natural gas revenue totaled $434.1 million in 2003, as compared to $384.2 million in 2002 (2001 – $509.9 million). The increase in revenue is due to higher commodity prices, mitigated partially by lower natural gas production volumes as compared to the prior year. Natural gas production volumes averaged 153 MMcf/d in 2003, a 37 percent decrease from the 241 MMcf/d produced in 2002 (2001 – 225 MMcf/d), primarily as a result of the disposition of Northeast Alberta assets to the Trust (the "Trust assets") in the first quarter of 2003, as well as other property dispositions closed during the year. Production from the Trust assets averaged 97 MMcf/d in 2002. Stronger natural gas demand resulted in an increase of 70 percent in Paramount's average natural gas sales price before hedging to $5.99/Mcf as compared to $3.53/Mcf in 2002 (2001 – $5.93/Mcf). Paramount's average natural gas price after hedging was $5.16/Mcf as compared to $4.08/Mcf in 2002 (2001 – $6.12/Mcf).

Oil and natural gas liquids ("NGL") prices before hedging averaged $38.27/Bbl in 2003, as compared to $35.20/Bbl in 2002 (2001 – $35.48/Bbl). Oil and NGL production increased 27 percent to average 7,169 Bbl/d in 2003 as compared to 5,663 Bbl/d in 2002 (2001 – 2,165 Bbl/d). This increase is attributable to the inclusion in 2003 results of a full year of production from the assets obtained through the acquisition of Summit Resources Limited ("Summit").

Paramount's 2003 production profile continues to be significantly weighted to natural gas, despite the acquisition of Summit in 2002. Summit production was approximately 60 percent natural gas and 40 percent oil and NGL at the time of acquisition. In 2003 natural gas production contributed 78 percent of Paramount's total production compared to 88 percent in 2002 (2001 – 95 percent). With the disposition of the Sturgeon Lake property in the fourth quarter of 2003, the Company expects 2004 production to continue to be strongly weighted towards natural gas.

Fourth quarter petroleum and natural gas revenue before hedging totaled $86.1 million as compared to $135.0 million for the comparable quarter in 2002 (2001 – $65.1 million). The decrease in revenue is due to lower production volumes, mitigated partially by higher commodity prices before hedging. Natural gas production volumes averaged 141 MMcf/d during the fourth quarter, a decrease of 46 percent as compared to 263 MMcf/d for the comparable quarter in 2002 (2001 – 218 MMcf/d). Lower natural gas production is a result of the disposition of the Trust assets, the completion of a successful disposition program of non-core, non-operated natural gas properties, and lower production levels in the Kaybob area in comparison to the fourth quarter of 2002. Oil and NGL sales averaged 5,877 Bbl/d in the fourth quarter of 2003 as compared to 8,552 Bbl/d for the comparable quarter in 2002 (2001 – 2,002 Bbl/d). Decreased oil and NGL production is primarily due to the sale of Sturgeon Lake and other minor oil properties in the current year, partially offset by new oil production at Cameron Hills.

The Alberta Securities Commission released National Instrument 51-101 (the "Instrument") in 2003, with an effective date of September 30, 2003. The Instrument requires all reported petroleum and natural gas production to be measured in marketable quantities, with adjustments for heat content included in the commodity price reported. The Company has adopted the Instrument prospectively. As such, fourth quarter natural gas production volumes are measured in marketable quantities, with adjustments for heat content and transportation reflected in the reported natural gas price.

Paramount's financial success is contingent upon the growth of reserves and production volumes and the economic environment that creates a demand for natural gas and crude oil. Such growth is a function of the amount of cash flow that can be generated and reinvested into a successful capital expenditure program. To protect cash flow against commodity price volatility, the Company will, from time to time, manage cash flow by utilizing commodity price hedges. The hedging program is generally for periods of less than one year and would not exceed 50 percent of Paramount's current production volumes.

At December 31, 2003, Paramount had the following commodity price hedges in place:

AECO	Price	Term
10,000 GJ/d	$ 7.35	January 2004 – March 2004
10,000 GJ/d	$ 6.26	January 2004 – March 2004
10,000 GJ/d	$ 6.14	January 2004 – March 2004
20,000 GJ/d	$ 6.51	January 2004 – March 2004
10,000 GJ/d	$ 5.55	April 2004 – October 2004
10,000 GJ/d	$ 5.51	April 2004 – October 2004
WTI		
1,000 Bbl/d	US $ 24.07	May 2002 – April 2004
1,000 Bbl/d	US $ 25.00 – $ 30.25 collar	January 2004 – December 2004

Had these financial contracts been settled on December 31, 2003, using prices in effect at that time, the mark to market before tax loss would have totaled $1.6 million.

Subsequent to year end, the Company entered into the following hedging arrangements:

AECO	Price	Term
20,000 GJ/d	$ 5.80	April 2004 – October 2004
10,000 GJ/d	$ 5.81	April 2004 – October 2004
10,000 GJ/d	$ 5.86	April 2004 – October 2004
10,000 GJ/d	$ 5.25 – $ 6.80 collar	April 2004 – October 2004
10,000 GJ/d	$ 5.25 – $ 6.75 collar	April 2004 – October 2004

Commodity hedging gains and losses are recorded based on monthly cash settlements with counterparties. Where hedging contracts are terminated before the end of the contract, the resulting payment or cash receipt is recorded as deferred revenue or deferred hedging loss on the Company's balance sheet and amortized into income over the initial life of the contract.

The Company is exposed to credit risk from financial instruments to the extent of non-performance by third parties, and non-performance by counterparties to swap agreements. The Company minimizes credit risk associated with possible non-performance by financial instrument counterparties by entering into contracts with only highly rated counterparties and controls third-party credit risk with credit approvals, limits on exposures to any one counterparty, and monitoring procedures.

The Company also has in place foreign exchange hedges, which have fixed the exchange rate on US $24.4 million for CDN $34.9 million over the next two years at CDN $1.4335. For the year ended December 31, 2003, gross revenue included gains from foreign currency hedging activity of $0.5 million (2002 – $3.4 million loss and 2001 – $1.7 million loss). At December 31, 2003, the estimated fair value of these hedges based on the Company's assessment of available market information was $3.3 million.

During 2003, approximately 75 percent of Paramount's natural gas sales were under long-term contracts to gas aggregators and direct-sales purchasers as compared to 43 percent and 42 percent for 2002 and 2001, respectively. The increase in the percentage is due to the lower production volumes as a result of the transfer of the Trust assets in early 2003. Despite transferring approximately 97 MMcf/d of natural gas production to the Trust, Paramount kept the majority of the long-term contracts for natural gas sales.

Netbacks ($/Boe)	**2003**	2002	2001
Gross revenue before hedging	**$ 36.53**	$ 25.50	$ 35.40
Royalties	**6.93**	4.44	6.89
Operating costs	**6.82**	5.14	4.22
Operating netback	**22.78**	15.92	24.29
Commodity hedging loss (gain)	**4.47**	(2.79)	(1.09)
General and administrative [1]	**1.57**	0.95	0.85
Bad debt expense	**0.50**	–	–
Lease rentals	**0.30**	0.27	0.30
Interest on long-term debt [2]	**1.66**	1.43	1.33
Current and Large Corporations tax	**0.24**	0.55	1.92
Cash flow netback	**$ 14.04**	$ 15.51	$ 20.98

(1) Net of non-cash general and administrative expenses.

(2) Net of non-cash interest expense.

In 2003 Paramount experienced a loss on short-term investments of $1.0 million, as compared to a gain of $40.8 million in 2002. In the second quarter of 2003, Paramount wrote off its investment in Jurassic Oil and Gas Ltd, a private exploration company based in Calgary. Paramount routinely utilizes a portion of its working capital to make short-term investments in private and publicly traded oil and gas companies. Accordingly, related gains and losses are included in cash flow from operations.

Royalties (thousands of dollars)	**2003**	2002	2001
Crown royalties	**$ 79,496**	$ 71,535	$ 94,253
Other royalties	**3,516**	3,658	5,953
	83,012	75,193	100,206
Alberta Royalty Tax Credit	**(500)**	(749)	(500)
Net royalties	**$ 82,512**	$ 74,444	$ 99,706
Average corporate royalty rate as a percentage of petroleum and natural gas revenue before hedging	**19.0%**	19.4%	19.6%

For 2003, net royalties increased to $82.5 million from $74.4 million in 2002 (2001 – $99.7 million) due to higher natural gas prices. As a percentage of revenue, Paramount's corporate royalty rate is substantially unchanged from the prior year, at 19.0 percent compared to 19.4 percent in 2002.

Fourth-quarter royalties totaled $10.7 million as compared to $28.2 million for the fourth quarter in 2002 (2001 – $12.4 million). The decrease in royalty costs reflects the decrease in production volumes offset partially by higher commodity prices.

Operating Expenses (thousands of dollars)	**2003**	2002	2001
Operating expenses	**$ 81,193**	$ 86,067	$ 61,045
Net operating expenses per Boe	**$ 6.82**	$ 5.14	$ 4.22

Paramount's 2003 operating expenses decreased six percent to $81.2 million from $86.1 million in 2002 (2001 – $61.0 million). On a units-of-production basis, operating costs increased to $6.82/Boe from $5.14/Boe in 2002 (2001 – $4.22/Boe). The Company experienced a general increase in the costs of goods and services including higher labour and energy costs. These increases, combined with a decrease in production, resulted in the Company having higher than expected unit operating expenses. Paramount constructs and operates plant facilities and gathering systems as a corporate strategy in order to control the flow of its natural gas to market. These facilities incur fixed costs, which are in addition to the costs incurred at the well level, thereby increasing total operating expenses and the relative magnitude of the per unit costs.

Fourth quarter operating costs decreased to $22.3 million as compared to $23.5 million a year earlier, primarily due to the decreased well and production base resulting from the sale of the Trust assets and other assets earlier in 2003. Fourth quarter operating costs increased on a units-of-production basis to $8.25/Boe from $4.88/Boe for the comparable quarter in 2002. The increase in unit operating costs is primarily a result of charges stemming from the settlement of a dispute with a facility operator, as well as post-closing adjustments related to the Sturgeon Lake property sale incurred during the quarter.

General and Administrative Expenses

General and Administrative Expenses (thousands of dollars)	**2003**	2002	2001
Gross general and administrative expenses	**$ 31,539**	$ 30,868	$ 26,374
Operating recoveries	**(12,855)**	(15,238)	(15,766)
General and administrative expenses before stock-based compensation	**18,684**	15,630	10,608
Stock-based compensation expenses	**1,214**	582	1,738
Net general and administrative expenses	**$ 19,898**	$ 16,212	$ 12,346
Net general and administrative expenses per Boe	**$ 1.67**	$ 0.97	$ 0.85

General and administrative expenses, net of operating recoveries and before stock-based compensation expenses, increased to $18.7 million in 2003 as compared to $15.6 million in 2002 (2001 – $10.6 million). General and administrative costs, post-disposition of Trust assets, did not decrease, as Paramount has increased its corporate staffing levels in order to enable the Company to identify and develop new core areas and build its production portfolio. This initiative has resulted in Paramount advancing its long-term projects such as Colville Lake, Northeast Alberta bitumen and coal bed methane, and developing successful new fields in existing core areas within Grande Prairie and Northwest Alberta. The Company has also increased administrative staff levels to ensure compliance with new corporate and reporting obligations in Canada and the United States; certain of these are a result of the US debt offering closed in 2003. Operating recoveries are lower in 2003 by comparison to the prior year due to a lower well count and reduced field staff, as a result of the disposition of the Trust assets and other assets in 2003. Paramount does not capitalize any general and administrative expenses.

In 2003, Paramount adopted the new recommendation of the Canadian Institute of Chartered Accountants ("CICA") related to stock-based compensation. The recommendation has been adopted prospectively, with no restatement of prior periods. As a result, the Company recorded a non-cash provision of $1.2 million in the fourth quarter in respect of stock options granted during 2003. Stock-based compensation expenses incurred in prior years were in respect of the Company's Share Appreciation Rights Plan, which was cancelled in February 2003.

Interest Expense

Interest Expense (thousands of dollars)	**2003**	2002	2001
Interest expense	**$ 19,917**	$ 23,943	$ 19,291
Total debt, December 31	**$ 298,561**	$ 539,270	$ 316,600
Average debt outstanding for the period	**$ 340,919**	$ 448,951	$ 295,456

Interest expense decreased to $19.9 million in 2003 from $23.9 million in 2002 (2001 – $19.3 million). The decrease reflects lower average debt levels for the Company in 2003 as a result of the disposition of the Trust assets, offset somewhat by the higher cost of borrowing of the US $ notes in the current year.

Dry Hole Costs

Under the successful efforts method of accounting, costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to dry hole expense. Other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to exploration expense as incurred. For 2003, dry hole costs amounted to $36.6 million as compared to $120.1 million in 2002 (2001 – $8.9 million). The 2003 provision includes $6.1 million of costs associated with wells drilled in the current year and $30.5 million associated with exploratory wells drilled in Canada and the United States in previous years, which the Company has determined will not be capable of production in economic quantities.

Geological and geophysical expenses decreased during 2003 to $8.5 million from $9.3 million in the previous year (2001 – $10.6 million).

The current year provision for depletion and depreciation expense totaled $163.4 million as compared to $169.4 million in 2002 (2001 – $105.4 million). Depletion and depreciation expense includes expired lease costs of $10.2 million. On a units-of-production basis, depletion and depreciation costs averaged $13.72/Boe as compared to $10.11/Boe in 2002 (2001 – $7.28/Boe). Depletion rates in 2003 were affected by the Summit acquisition and the addition of capital costs previously excluded from the depletable base.

Under the successful efforts method of accounting, depletion and depreciation is provided based on estimated proved recoverable reserves of each producing property. Capital costs associated with undeveloped land of $147 million and non-producing petroleum and natural gas properties of $62 million totaling $209 million are excluded from capital costs subject to depletion in 2003 (2002 – $367 million).

On an annual basis the Company reviews the liability for future site restoration and abandonment costs. For 2003 the provision totaled $4.5 million as compared to $3.4 million in 2002. At December 31, 2003, the Company's estimates for site restoration of its petroleum and natural gas properties totaled approximately $57 million (2002 – $58 million), of which $21.1 million is currently reflected as an accumulated provision in the financial statements (2002 – $23.0 million).

The Company has recorded a provision of $10.4 million in 2003 (2002 – $31.3 million) in respect of impairment in certain non-core properties in Alberta, Saskatchewan and Montana.

In 2003, Paramount recorded Large Corporations and other tax expense of $2.9 million as compared to $9.2 million in 2002. The 2002 tax expense includes approximately $5.7 million in respect of prior year tax assessments.

In 2003, the Alberta provincial and Canadian federal governments introduced legislation to reduce corporate income taxes. The changes are considered substantively enacted for the purposes of Canadian GAAP and, accordingly, the Company has recorded a future income tax benefit of $30.3 million in the current year.

The future income tax recovery recorded for 2003 totaled $62.2 million, as compared to $46.9 million in 2002.

Estimated Income Tax Pools (millions of dollars)	**December 31, 2003**
Undepreciated capital costs (UCC)	$ 215
Canadian oil and gas property expenses (COGPE)	25
Canadian exploration expenses (CEE)	68
Canadian development expenses (CDE)	166
Other	21
Total estimated income tax pools	$ 495

Paramount has available approximately $495 million of unutilized tax pools at December 31, 2003. These tax pools will be available for deduction in 2004 in accordance with Canadian income tax regulations at varying rates of amortization.

(thousands of dollars, except per share amounts)		**2003**	2002	2001
Cash flow from operations		**$ 167,276**	$ 259,916	$ 303,937
Cash flow from operations per share	– basic	**$ 2.78**	$ 4.37	$ 5.11
	– diluted	**$ 2.77**	$ 4.36	$ 5.11
Net earnings		**$ 2,633**	$ 10,307	$ 118,902
Earnings per share	– basic	**$ 0.04**	$ 0.17	$ 2.00
	– diluted	**$ 0.04**	$ 0.16	$ 2.00

Paramount's cash flow from operations decreased 36 percent to $167.3 million from $259.9 million in 2002. Lower cash flows were primarily a result of $53 million in commodity hedging losses in 2003 as opposed to $47 million in commodity hedging gains in 2002, partially offset by a $50 million increase in petroleum and natural gas revenues due to higher commodity prices. A $40 million gain on sale of the investment in Peyto Exploration was also included in 2002 cash flows.

Fourth-quarter cash flow totaled $43.2 million, a decrease of 30 percent from $62.1 million during the same period in 2002 (2001 – $47.7 million). The decrease in cash flows is a result of lower production levels as compared to the fourth quarter of 2002.

The Company recorded net earnings of $2.6 million, as compared to net earnings of $10.3 million in 2002. The lower earnings in 2003 are primarily due to lower cash flows, as well as the inclusion of $37 million Surmont compensation in 2002 net earnings.

Quarterly Information

Historical quarterly information, prepared by the Company in Canadian dollars and in accordance with GAAP, is as follows:

	Fiscal 2003 Three Months Ended			
(thousands of dollars, except per share amounts)	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**
Net revenues	**$ 77,697**	**$ 66,004**	**$ 65,127**	**$ 90,507**
Net earnings (loss)	**$ 11,296**	**$ (7,851)**	**$ (1,436)**	**$ 624**
Net earnings (loss) per common share – basic	**$ 0.18**	**$ (0.13)**	**$ (0.02)**	**$ 0.01**
– diluted	**$ 0.18**	**$ (0.13)**	**$ (0.02)**	**$ 0.01**

	Fiscal 2002 Three Months Ended			
(thousands of dollars, except per share amounts)	Dec. 31	Sept. 30	June 30	Mar. 31
Net revenues	$ 110,180	$ 95,780	$ 110,206	$ 83,332
Net earnings (loss)	$ (41,399)	$ 6,180	$ 26,614	$ 18,912
Net earnings (loss) per common share – basic	$ (0.70)	$ 0.10	$ 0.45	$ 0.32
– diluted	$ (0.70)	$ 0.10	$ 0.44	$ 0.32

Quarterly net revenues in 2003, as compared to the same periods in 2002, reflect lower production volumes as a result of the disposition of the Trust assets in the first quarter of 2003, partially offset by higher commodity prices. Quarterly net earnings are lower in 2003 as compared to 2002 primarily due to reduced production levels, combined with commodity hedging losses incurred during the current year.

The net loss of $41.4 million in the fourth quarter of 2002 is primarily due to dry hole costs and impairment charges on non-core properties recorded in the quarter.

Capital Expenditures

Capital Expenditures (thousands of dollars)	**2003**	2002	2001
Land	**$ 22,288**	$ 6,410	$ 39,166
Geological and geophysical	**8,450**	9,303	10,646
Drilling	**123,455**	124,076	127,736
Production equipment and facilities	**69,560**	77,407	94,775
Exploration and development expenditures	**223,753**	217,196	272,323
Summit Resources Limited acquisition	**–**	251,422	–
Property acquisitions	**937**	28,610	19,048
Proceeds received on property dispositions	**(371,601)**	(5,042)	(5,183)
Other	**1,933**	2,349	1,166
Net capital expenditures	**$ (144,978)**	$ 494,535	$ 287,354
Property, plant and equipment, net, December 31	**$ 1,006,205**	$ 1,411,961	$ 1,058,337
Total assets, December 31	**$ 1,147,848**	$ 1,526,786	$ 1,176,323

During 2003, expenditures for exploration and development activities totaled $223.8 million as compared to $217.2 million in 2002 (2001 – $272.3 million). A total of 211 gross (139 net) wells were drilled during the year, including 67 gross (41 net) wells in the fourth quarter, compared to 135 gross (99 net) wells in 2002 (2001 – 196 gross, 159 net).

Net capital expenditures amounted to a recovery of $145.0 million in 2003 as compared to expenditures of $494.5 million in 2002 (2001 – $287.4 million). The Company disposed of a number of properties during 2003, including the Trust assets, resulting in a net capital recovery for the year.

SHORT-TERM INVESTMENTS

The Company has the following short-term investments:

	Opening 2003 Shares	Purchased (Sold)	Closing 2003 Shares	Investment
Investments				
Fox Creek Petroleum Corp.	2,173,162	152,000	2,325,162	$ 2,538,000
Invertek [1]	7,500,000	11,531,250	19,031,250	1,525,192
Spearhead Resources Inc. [2]				5,990,000
Altius Energy Corp. [3]				4,398,197
Harvest Energy Trust		200,000	200,000	2,100,000
Jurassic Oil and Gas Ltd. [4]	850,000	–	850,000	–
				$ 16,551,389

(1) Investment in Invertek is through Wilson Drilling Ltd.

(2) Spearhead Resources Inc. $5 million eight percent and $990,000 10 percent secured convertible debentures due June 1, 2004.

(3) Altius Energy Corp. US $2.7 million 14 percent secured convertible debenture due April 9, 2005 plus accrued interest.

(4) The Company wrote off its investment in Jurassic Oil and Gas Ltd. in 2003.

INVESTMENT IN DRILLING COMPANY

Paramount owns a 50 percent equity interest in Wilson Drilling Ltd., a private company established to operate 3 drilling rigs in Western Canada. The Company accounts for its interest using proportionate consolidation whereby its pro-rata share of the financial results is combined on a line-by-line basis with similar items in the Company's financial statements.

INVESTMENT IN DRILLING PARTNERSHIP

Paramount owns a 99 percent interest in Shetah-Wilson Drilling Partnership, an entity established to operate 2 drilling rigs. The rigs are leased from an unrelated third party.

INVESTMENT IN PIPELINE COMPANY

Paramount owns a 50 percent equity interest, before payout (45 percent after payout) in Shiha Energy Transmission Ltd., a private company established to transport natural gas from operations in the Liard core area, Northwest Territories to facilities in British Columbia. The Company accounts for its interest using proportionate consolidation.

INVESTMENT IN ENGINEERING COMPANY

Paramount owns a 50 percent equity interest in a private company whose principal business is to provide consulting and technical engineering services. The Company accounts for its interest using proportionate consolidation.

During 2003, Paramount recognized in revenue $10.4 million (2002 – $39.4 million; 2001 – $1.2 million) of deferred revenue primarily related to the settlement of natural gas commodity hedging contracts that were previously put in place to mitigate the Company's commodity price risk. Paramount's accounting policy recognizes these gains in the accounting years of related production. The deferred hedging gains of $4.0 million at December 31, 2003 will be recognized in revenue in the first quarter of 2004.

Liquidity and Capital Resources

Paramount's capital structure as at December 31, 2003, was as follows:

(thousands of dollars, except per share amounts)	Amount	%	$/Share [1]
Debt			
US $ senior notes	$ 226,887	28	$ 3.78
Credit facility	60,350	8	1.00
Working capital deficiency	9,143	1	0.15
Other	11,324	1	0.19
Net debt	307,704	37	5.12
Shareholders' equity	501,642	63	8.35
Total capitalization	$ 809,346	100	$ 13.47

(1) At December 31, 2003 – 60,094,600 basic common shares outstanding.

DEBT

On October 27, 2003, the Company closed an offering of US $175 million of senior unsecured notes due 2010. Net proceeds were used to reduce existing bank indebtedness. The Company also has a committed revolving/non-revolving credit facility with a syndicate of Canadian chartered banks. The revolving nature of the facility expires on March 31, 2004. The Company has requested for an extension of the revolving credit facility of up to 364 days, subject to the approval of the lenders. To facilitate the documentation of this extension, the Company has agreed to amend the expiry date of the existing facility to April 30, 2004. To the extent that any lenders participating in the syndicate do not approve the 364-day extension, the amount due to those lenders will convert to a one-year non-revolving term loan with principal due in full on March 31, 2005. The borrowing base under this facility was $203 million at December 31, 2003. The borrowing base is adjusted annually by the syndicate based on a review of the Company's financial and reserve reports; it is expected that this adjustment will be made early in 2004. The magnitude and direction of the adjustment are not known at this time.

The Company's working capital deficiency at December 31, 2003, excluding shareholder loan and bank loans, was $9.1 million (2002 - $16.0 million). Paramount will likely show a working capital deficiency on its balance sheet, as receivables related to petroleum and natural gas sales are collected in 30 days, whereas joint venture partners and suppliers are typically paid on 60 day terms.

CONTRACTUAL OBLIGATIONS

Future contractual obligations, as at December 31, 2003, are as follows:

		Expected			
Contractual Obligations (thousands of dollars)	Total	Less than 1 year	2-3 years	4-5 years	After 5 years
US $ senior notes due 2010	$ 226,887	$ –	$ –	$ –	$ 226,887
Pipeline commitments	268,686	25,692	45,808	43,773	153,413
Operating leases	35,700	4,109	8,367	8,443	14,781
Total	$ 531,273	$ 29,801	$ 54,175	$ 52,216	$ 395,081

SHARE CAPITAL

As at December 31, 2003, the Company's issued share capital consisted of 60,094,600 common shares (December 31, 2002 – 59,458,600 common shares). Changes in share capital during 2002 and 2003 are as follows:

Common shares	Number	Consideration
Balance December 31, 2001	59,453,600	$ 189,320
Stock options exercised	5,000	72
Expenses recognized in respect of stock-based compensation	–	801
Balance December 31, 2002	59,458,600	$ 190,193
Stock options exercised	710,000	10,317
Shares repurchased	(74,000)	(236)
Balance December 31, 2003	**60,094,600**	**$ 200,274**

In February 2003, employees of the Company exercised 710,000 stock options for total consideration of $10.3 million.

Pursuant to its Normal Course Issuer Bid, Paramount repurchased 74,000 common shares for cancellation in 2003, at an average price of $9.53 per share. From January 1 to March 12, 2004, the Company has repurchased a total of 701,300 common shares at an average price of $10.86 per share. Common shares outstanding at March 12, 2004 are 59,393,300.

For 2004, the Company expects to fund its capital expenditure program primarily through cash flow from operations, supplemented by available amounts under its credit facility.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has a 99 percent interest in a drilling partnership, which has a long-term operating lease on two drilling rigs operating in western Canada. The Company entered into the partnership in order to secure access to drilling rigs during peak demand periods. Future payments in respect of the operating lease are disclosed in note 6 to the consolidated financial statements.

The Company's share of net operating income from the partnership amounted to $0.1 million in 2003 (2002 – loss of $0.8 million). These amounts have been recorded in the Company's consolidated statements of earnings.

DISPOSITION OF ASSETS TO PARAMOUNT ENERGY TRUST

In the first quarter of 2003, the Company transferred certain natural gas assets in Northeast Alberta to the Trust, a related party. The transaction, described under the heading "Significant Events", was accounted for at the net book value of the assets as recorded in Paramount.

NOTE PAYABLE TO PARAMOUNT OIL AND GAS LTD.

In 2002, in order to complement existing funding for the acquisition of Summit, the Company secured a $33 million loan from Paramount Oil and Gas Ltd., a related entity with a significant ownership interest in the Company. The loan was repaid on March 7, 2003.

Companies involved in the exploration for and production of oil and natural gas face a number of risks and uncertainties inherent in the industry. The Company's performance is influenced by commodity pricing, transportation and marketing constraints and government regulation and taxation.

Natural gas prices are influenced by the North American supply and demand balance as well as transportation capacity constraints. Seasonal changes in demand, which are largely influenced by weather patterns, also affect the price of natural gas.

Stability in natural gas pricing is available through the use of short and long-term contract arrangements. Paramount utilizes a combination of these types of contracts, as well as spot markets, in its natural gas pricing strategy. As the majority of the Company's natural gas sales are priced to US markets, the Canada/US exchange rate can strongly affect revenue.

Oil prices are influenced by global supply and demand conditions as well as for worldwide political events. As the price of oil in Canada is based on a US benchmark price, variations in the Canada/US exchange rate further affect the price received by Paramount for its oil.

The Company's access to oil and natural gas sales markets is restricted, at times, by pipeline capacity. In addition, it is also affected by the proximity of pipelines and availability of processing equipment. Paramount intends to control as much of its marketing and transportation activities as possible in order to minimize any negative impact from these external factors.

The oil and gas industry is subject to extensive controls, regulatory policies and income taxes imposed by the various levels of government. These controls and policies, as well as income tax laws and regulations, are amended from time to time. The Company has no control over government intervention or taxation levels in the oil and gas industry; however, it operates in a manner intended to ensure that it is in compliance with all regulations and is able to respond to changes as they occur.

Paramount's operations are subject to the risks normally associated with the oil and gas industry including hazards such as unusual or unexpected geological formations, high reservoir pressures and other conditions involved in drilling and operating wells. The Company attempts to minimize these risks using prudent safety programs and risk management, including insurance coverage against potential losses.

The Company recognizes that the industry is faced with an increasing awareness with respect to the environmental impact of oil and gas operations. Paramount has reviewed the environmental risks to which it is exposed and has determined that there is no current material impact on the Company's operations; however, the cost of complying with environmental regulations is increasing. Paramount intends to ensure continued compliance with environmental legislation.

2004 Outlook and Sensitivity Analysis

The Company's earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond the control of the Company. Current volatility in commodity prices creates uncertainty as to Paramount's cash flow and capital expenditure budget. The Company will therefore assess results throughout the year and revise forecasts as necessary to reflect the most current information. The following analysis assesses the magnitude of these sensitivities on the Company's 2004 cash flow using the following base assumptions:

(a) 2004 Production	
Natural gas	160 MMcf/d
Crude oil/liquids	6,000 Bbl/d
(b) 2004 Average Prices	
Natural gas	$5.68/Mcf
Crude oil/liquids (W.T.I.)	US $28.00/Bbl
(c) 2004 Exchange Rate (CDN $/US $)	$0.75

The following analysis assesses the estimated impact on cash flow with variations in production, prices, interest and exchange rates:

Sensitivity	Cash Flow Effect (millions of dollars)
Gas sales change of 10 MMcf/d	$ 16.6
Gas price change of $0.10/Mcf	$ 4.7
Oil and natural gas liquids sales change of 100 Bbl/d	$ 0.9
Oil and natural gas liquids price change of $1.00/Bbl (W.T.I)	$ 2.3
Sensitivity to Canada/US exchange rate fluctuation of CDN $0.01	$ 0.5
Average interest rate change of one percent	$ 0.6

Critical Accounting Estimates

The MD&A is based on the Company's consolidated financial statements, which have been prepared in Canadian dollars in accordance with GAAP. The application of GAAP requires management to make estimates, judgements and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Paramount bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions.

The following is a discussion of the critical accounting estimates that are inherent in the preparation of the Company's consolidated financial statements and notes thereto.

ACCOUNTING FOR PETROLEUM AND NATURAL GAS OPERATIONS

Under the successful efforts method of accounting, the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves, including acquisitions, successful exploratory wells, development costs and the costs of support equipment and facilities. Exploration expenditures, including geological and geophysical costs, lease rentals, and exploratory dry holes are charged to earnings in the period incurred. Certain costs of exploratory wells are capitalized pending determination that proved reserves have been found. Such determination is dependent upon, among other things, the results of planned additional wells and the cost of required capital expenditures to produce the reserves found.

The application of the successful efforts method of accounting requires management's judgement to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results of a drilling operation can take considerable time to analyze, and the determination that proved reserves have been discovered requires both judgement and application of industry experience. The evaluation of petroleum and natural gas leasehold acquisition costs requires management's judgement to evaluate the fair value of exploratory costs related to drilling activity in a given area.

RESERVE ESTIMATES

Estimates of the Company's reserves included in its consolidated financial statements are prepared in accordance with guidelines established by the Alberta Securities Commission. Reserve engineering is a subjective process of estimating underground accumulations of petroleum and natural gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgement of the persons preparing the estimate.

Paramount's reserve information is based on estimates prepared by its independent petroleum consultants. Estimates prepared by others may be different than these estimates. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve estimates may be different from the quantities of petroleum and natural gas that are ultimately recovered. In addition, the results of drilling, testing and production after the date of an estimate may justify revisions to the estimate.

The present value of future net revenues should not be assumed to be the current market value of the Company's estimated reserves. Actual future prices, costs and reserves may be materially higher or lower than the prices, costs and reserves used for the future net revenue calculations.

The estimates of reserves impact depletion, dry hole and site restoration expenses. If reserve estimates decline, the rate at which the Company records depletion and site restoration expenses increases, reducing net earnings. In addition, changes in reserve estimates may impact the outcome of Paramount's assessment of its petroleum and natural gas properties for impairment.

IMPAIRMENT OF PETROLEUM AND NATURAL GAS PROPERTIES

The Company reviews its proved properties for impairment annually on a field basis. For each field, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of those properties may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved and probable petroleum and natural gas reserves, as estimated by the Company on the balance sheet date. Reserve estimates, as well as estimates for petroleum and natural gas prices and production costs may change, and there can be no assurance that impairment provisions will not be required in the future.

Unproved leasehold costs and exploratory drilling in progress are capitalized and reviewed periodically for impairment. Costs related to impaired prospects or unsuccessful exploratory drilling are charged to earnings. Acquisition costs for leases that are not individually significant are charged to earnings as the related leases expire. Further impairment expense could result if petroleum and natural gas prices decline in the future of if negative reserve revisions are recorded, as it may be no longer economic to develop certain unproved properties. Management's assessment of, among other things, the results of exploration activities, commodity price outlooks and planned future development and sales impacts the amount and timing of impairment provisions.

FUTURE SITE RESTORATION AND ABANDONMENT COSTS

The site restoration provision recorded in the consolidated financial statements is based on an estimate for total costs for future site restoration and abandonment of the Company's petroleum and natural gas properties. This estimate is based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgements that are subject to future revisions based on numerous factors, including changing technology and political and regulatory environments.

Beginning in 2004, the Company will adopt the Canadian Institute of Chartered Accountants ("CICA") Handbook section 3110 – Asset Retirement Obligation, which will result in changes in accounting for site restoration and abandonment costs. See "Recent Accounting Pronouncements" section.

INCOME TAXES

The Company records future tax assets and liabilities to account for the expected future tax consequences of events that have been recorded in its consolidated financial statements and its tax returns. These amounts are estimates; the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flows and capital expenditures in current and future periods. We periodically assess the realizability of our future tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance.

Recent Accounting Pronouncements

IMPAIRMENT OF LONG-LIVED ASSETS

The CICA recently issued Handbook Section 3063 – Impairment of Long-Lived Assets. This new section establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets by profit-oriented enterprises. The section is effective for fiscal years beginning on or after April 1, 2003.

Under the new section, impairment of long-lived assets held for use is determined by a two-step process, with the first step determining when an impairment is recognized and the second step measuring the amount of the impairment. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent. An impairment loss is recognized when the carrying amount of a long-lived asset exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is measured as the amount by which the long-lived asset's carrying amount exceeds its fair value. This represents a significant change to Canadian GAAP, which previously measured the amount of the impairment as the difference between the long-lived asset's carrying value and its net recoverable amount (i.e. undiscounted cash flows plus residual value). The Company anticipates that adoption of this pronouncement will not have a material effect on its consolidated financial statements.

DISPOSAL OF LONG-LIVED ASSETS AND DISCONTINUED OPERATIONS

The CICA recently issued Handbook Section 3475 – Disposal of Long-Lived Assets and Discontinued Operations, which establishes standards for the recognition, measurement, presentation and disclosure of the disposal of long-lived assets by profit-oriented enterprises. It also establishes standards for the presentation and disclosure of discontinued operations.

Although earlier adoption is encouraged, Section 3475 applies to disposal activities initiated by a company's commitment to a plan on or after May 1, 2003. The Company anticipates that adoption of this pronouncement will not have a material effect on its consolidated financial statements.

VARIABLE INTEREST ENTITIES

The CICA recently issued Accounting Guideline No. 15 – Consolidation of Variable Interest Entities. The guideline requires the consolidation of entities in which an enterprise absorbs a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. Currently, entities are generally consolidated by an enterprise when it has a controlling financial interest through ownership of a majority voting interest in the entity. The guideline applies to annual and interim periods beginning on or after November 1, 2004, except for certain disclosure requirements. Entities should provide disclosures about variable interest entities in which they hold significant interests for periods beginning on or after January 1, 2004. The Company does not expect the implementation of this guideline to have a material impact on its financial statements.

ASSET RETIREMENT OBLIGATION

The CICA recently issued Handbook Section 3110 – Asset Retirement Obligation which addresses statutory, regulatory, contractual and other legal obligations associated with the retirement of a tangible long-lived asset that results from its acquisition, construction, development or normal operation.

Under Section 3110, asset retirement obligations are initially measured at fair value at the time the obligation is incurred with a corresponding amount capitalized as part of the asset's carrying value and depreciated over the asset's useful life using a systematic and rational allocation method.

On initial recognition, the fair value of an asset retirement obligation is determined based upon the expected present value of future cash flows. In subsequent periods, the carrying amount of the liability would be adjusted to reflect (a) the passage of time, and (b) revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

The change in liability due to the passage of time is measured by applying an interest method of allocation to the opening liability and is recognized as an increase in the carrying value of the liability and an expense. The expense must be recorded as an operating item in the income statement, not as a component of interest expense. A change in the liability resulting from revisions to either the timing or the amount of the original estimate of undiscounted cash flows is recognized as an increase or decrease in the carrying amount of the liability with an offsetting increase or decrease in the carrying amount of the associated asset.

For the year ended December 31, 2003, property, plant and equipment would increase by $16.2 million, site restoration liability would increase by $38.2 million and retained earnings would decrease by $22.0 million.

STOCK-BASED COMPENSATION AND OTHER STOCK-BASED PAYMENTS

In December 2001, the CICA issued Handbook Section 3870 – Stock-Based Compensation and Other Stock-Based Payments, which requires fair value accounting for all stock-based payments to non-employees, and for employees awards that are direct awards of stock, or call for settlement in cash or other assets, and for stock appreciation rights. For all other employee awards, the present standard allows disclosure of pro forma net income and pro forma earnings per share in the income statement. In October 2003, the CICA amended Handbook Section 3870 to require recognition of expense, based on the fair value method, for all employee stock-based compensation transactions for fiscal years beginning on or after January 1, 2004.

The recommendations of the Section should also be applied to the following awards that were outstanding at the start of the first fiscal year beginning on or after January 1, 2002, in which adoption of this Section was initially applied:

(a) Awards that call for settlement in cash or other assets;

(b) Stock appreciation rights that call for settlement by the issuance of equity instruments; and

(c) Any other award that is modified so as to become an award included in (a) or (b) above. The award should be accounted for as a new award, and not using modification accounting.

The cumulative amount, applicable to (a) or (b) above, that would have been recognized in prior years had this section been applied, less any amount previously recognized, should be recognized as the effect of a change in accounting policy and charged to opening retained earnings for the fiscal year in which this Section is initially applied, without restatement of prior periods.

The Company adopted the fair-value method of accounting for stock options for fiscal 2003. The fair-value based method will be applied prospectively, whereby compensation costs will be recognized for all options granted on or after January 1, 2003. Adoption of this accounting policy has resulted in an expense of $1.2 million being recorded in the Company's financial statements for the year ended December 31, 2003.

Management's Report

The accompanying consolidated financial statements of Paramount Resources Ltd. and all the information in this Annual Report are the responsibility of management and have been approved by the Board of Directors.

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the consolidated financial statements.

Management maintains systems of internal accounting and administrative controls of high quality, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are appropriately accounted for and adequately safeguarded.

The Audit Committee of the Board of Directors is comprised of non-management directors. The Audit Committee meets quarterly with management as well as the external auditors to discuss auditing matters and financial reporting issues and to satisfy itself that each party is properly discharging its responsibility. The Audit Committee also meets with management and the external auditors to discuss internal controls over the financial reporting process and to review the Annual Report. The Audit Committee reports its findings to the Board of Directors for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board of Directors and approval by the shareholders, the engagement or re-appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian generally accepted auditing standards in Canada on behalf of the shareholders. Ernst & Young LLP have full and free access to the Audit Committee and management.

Clayton H. Riddell
Chief Executive Officer

Bernard K. Lee
Chief Financial Officer

March 12, 2004

Auditors' Report

To the Shareholders of Paramount Resources Ltd.:

We have audited the consolidated balance sheets of Paramount Resources Ltd. as at December 31, 2003 and 2002, and the consolidated statements of earnings and retained earnings and cash flow for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants

Calgary, Canada

March 12, 2004

Consolidated Balance Sheets

As at December 31 (thousands of dollars)	**2003**	2002
ASSETS (note 8)		
Current Assets		
Short-term investments (market value: 2003 – $17,265; 2002 – $14,168)	**$ 16,551**	$ 14,168
Accounts receivable	**84,183**	91,042
Prepaid expenses	**2,282**	9,615
	103,016	114,825
Property, Plant and Equipment (note 5)		
Property, plant and equipment, at cost	**1,420,540**	1,961,369
Accumulated depletion and depreciation	**(414,335)**	(549,408)
	1,006,205	1,411,961
Goodwill (note 2)	**31,621**	–
Other Assets (note 8)	**7,006**	–
	$ 1,147,848	$ 1,526,786
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 112,159**	$ 130,798
Shareholder loan (note 9)	**–**	33,000
Bank loans (note 7)	**1,450**	498,097
	113,609	661,895
Long-term debt (note 8)	**297,111**	8,173
Provision for future site restoration and abandonment costs	**21,114**	22,954
Deferred revenue (note 12)	**3,959**	7,804
Future income taxes (note 11)	**210,413**	279,855
	532,597	318,786
Commitments and contingencies (notes 6, 12 and 14)		
Shareholders' equity		
Share capital (note 10)		
Issued and outstanding		
60,094,600 common shares (2002 – 59,458,600 common shares)	**200,274**	190,193
Contributed surplus	**746**	–
Retained earnings	**300,622**	355,912
	501,642	546,105
	$ 1,147,848	$ 1,526,786

See accompanying notes to consolidated financial statements

On behalf of the Board

C. H. Riddell
Director

J.B. Roy
Director

Consolidated Statements of Earnings and Retained Earnings

Years ended December 31 (thousands of dollars except for per share amounts)	**2003**	2002
Revenue		
Petroleum and natural gas sales	**$ 434,059**	$ 384,188
Commodity hedging (loss) gain	**(53,204)**	46,813
Royalties (net of ARTC)	**(82,512)**	(74,444)
(Loss) gain on sale of investments (note 16)	**(1,020)**	40,830
Other income	**2,012**	2,111
	299,335	399,498
Expenses		
Operating	**81,193**	86,067
Interest	**19,917**	23,943
General and administrative	**19,898**	16,212
Bad debt expense	**5,977**	–
Lease rentals	**3,574**	4,552
Geological and geophysical	**8,450**	9,303
Dry hole costs (note 5)	**36,600**	120,058
(Gain) loss on sales of property and equipment	**3,660**	(12)
Provision for future site restoration and abandonment costs	**4,462**	3,437
Depletion and depreciation	**163,413**	169,433
Write-down of petroleum and natural gas properties (note 5)	**10,418**	31,254
Unrealized foreign exchange gain on US debt (note 12)	**(1,566)**	–
Surmont compensation – net (note 15)	**–**	(37,291)
	355,996	426,956
Earnings (loss) before taxes	**(56,661)**	(27,458)
Income and other taxes (note 11)		
Large Corporations Tax and other	**2,875**	9,150
Future income tax recovery	**(62,169)**	(46,915)
	(59,294)	(37,765)
Net earnings	**2,633**	10,307
Retained earnings, beginning of year	**355,912**	346,064
Adjustment on disposition of assets to a related party (note 4)	**(6,923)**	–
Dividends declared (note 4)	**(51,000)**	–
Adoption of new accounting policies (note 3)	**–**	(459)
Retained earnings, end of year	**$ 300,622**	$ 355,912
Net earnings per common share (note 10)		
– basic	**$ 0.04**	$ 0.17
– diluted	**$ 0.04**	$ 0.16
Weighted average common shares outstanding (thousands) (note 10)		
– basic	**60,098**	59,458
– diluted	**60,472**	59,567

See accompanying notes to consolidated financial statements

Consolidated Statements of Cash Flows

Years ended December 31 (thousands of dollars except for per share amounts)	2003	2002
Operating activities		
Net earnings	**$ 2,633**	$ 10,307
Add (deduct) non-cash items		
Depletion and depreciation	**163,413**	169,433
Write-down of petroleum and natural gas properties	**10,418**	31,254
(Gain) loss on sales of property and equipment	**3,660**	(12)
Provision for future site restoration and abandonment costs	**4,462**	3,437
Future income tax recovery	**(62,169)**	(46,915)
Amortization of other assets	**161**	–
Non-cash general and administrative expenses	**1,214**	342
Unrealized foreign exchange gain on US debt	**(1,566)**	–
Write-down of Surmont assets	**–**	9,136
Add items not related to operating activities		
Surmont compensation	**–**	(46,427)
Dry hole costs	**36,600**	120,058
Geological and geophysical costs	**8,450**	9,303
Cash flow from operations	**167,276**	259,916
Increase (decrease) in deferred revenue	**(3,845)**	6,073
Decrease in other assets	**(161)**	–
Change in non-cash operating working capital (note 13)	**(33,381)**	40,145
	129,889	306,134
Financing activities		
Bank loans – draws	**43,013**	153,682
Bank loans – repayments	**(477,608)**	(38,525)
Shareholder loan	**(33,000)**	33,000
Proceeds from US debt net of issuance costs	**221,447**	–
Capital stock – issued	**10,317**	72
Capital stock – repurchased	**(705)**	–
	(236,536)	148,229
Cash flow provided by operating and financing activities	**(106,647)**	454,363
Investing activities		
Property, plant and equipment expenditures	**(217,295)**	(209,848)
Acquisition of Summit Resources Ltd. (note 2)	**–**	(251,422)
Petroleum and natural gas property acquisitions	**(228)**	(28,420)
Geological and geophysical	**(8,450)**	(9,303)
Proceeds on sale of property, plant and equipment	**317,792**	4,423
Surmont compensation	**–**	46,427
Change in non-cash investing working capital (note 13)	**14,828**	(6,960)
Cash flow used in investing activities	**106,647**	(455,103)
(Decrease) increase in cash	**–**	(740)
Cash, beginning of year	**–**	740
Cash, end of year	**$ –**	$ –

See accompanying notes to consolidated financial statements

Notes to Consolidated Financial Statements

(all tabular amounts expressed in thousands of dollars)

1. Summary of Significant Accounting Policies

Paramount Resources Ltd. ("the "Company") is involved in the exploration and development of petroleum and natural gas primarily in Western Canada. The consolidated financial statements are stated in Canadian dollars and have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"), which differs in some respects from GAAP in the United States. These differences are quantified in note 18.

As a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. In management's opinion, the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's accounting policies summarized below.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Paramount Resources Ltd. and its wholly owned subsidiaries, Paramount Resources US LLC, 586319 Alberta Ltd., Summit Resources Limited, Summit Resources, Inc., 977554 Alberta Ltd. and 910083 Alberta Ltd.

The Company accounts for its interest in a drilling company, a drilling partnership, a pipeline company, and an engineering company where it exercises joint control using proportionate consolidation whereby its pro-rata shares of all assets, liabilities, revenues and expenses are combined on a line-by-line basis with similar items in the Company's financial statements.

(B) JOINT OPERATIONS

Certain of the Company's exploration, development and production activities related to petroleum and natural gas are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

(C) REVENUE RECOGNITION

Revenues associated with the sale of natural gas, crude oil, and natural gas liquids ("NGLs") owned by the Company are recognized when title passes from the Company to its customer.

Revenues from oil and natural gas production from properties in which the Company has an interest with other producers are recognized on the basis of the Company's net working interest.

(D) SHORT-TERM INVESTMENTS

Short-term investments consist of common shares and convertible instruments held for sale. These investments are carried at the lower of cost and market value.

(E) PROPERTY, PLANT AND EQUIPMENT

COST

Property, plant and equipment are recorded at cost. The Company follows the successful efforts method of accounting for petroleum and natural gas operations. Under this method the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry hole costs, are charged to earnings as incurred. Leasehold acquisition costs, including costs of drilling and equipping successful wells, are capitalized. The net costs of unproductive exploratory wells, abandoned wells and surrendered leases are charged to earnings in the year of abandonment or surrender. Gains or losses are recognized on the disposition of property, plant and equipment.

DEPLETION AND DEPRECIATION

Depletion of petroleum and natural gas properties including well development expenditures are provided on the unit-of production method based on estimated proven recoverable reserves of each producing property or project. Depreciation of production equipment, gas plants and gathering systems are provided on a straight-line basis over their estimated useful life varying from 12 to 40 years. Depreciation of other equipment is provided on a declining balance method at rates varying from 4 to 30 percent.

IMPAIRMENT

Producing areas and significant unproved properties are assessed annually, or as economic events dictate for potential impairment. Any impairment loss is the difference between the carrying value of the asset and its undiscounted net recoverable amount.

(F) FUTURE SITE RESTORATION AND ABANDONMENT COSTS

Estimated future site restoration and abandonment costs are provided for in the consolidated financial statements. This estimate, net of expected recoveries, includes the cost of equipment removal and environmental cleanup based upon current regulations and economic circumstances at year end. Actual site restoration costs are deducted from the provision in the year incurred.

(G) GOODWILL

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is not amortized and is assessed by the Company for impairment at least annually. Impairment is assessed based on a comparison of the fair value of the net assets acquired to the carrying value of the net assets, including goodwill. Any excess of the carrying value over and above fair value is the impairment amount, and is charged to earnings in the period identified.

(H) FOREIGN CURRENCY TRANSLATION

The Company's foreign operations are considered integrated and are translated into Canadian dollars using the temporal method.

Monetary assets and liabilities denominated in US dollars are translated into Canadian dollars at exchange rates in effect at the balance sheet date. Other assets and liabilities are translated at the rates prevailing at the respective transaction dates. Revenues and expenses are translated at the average rate prevailing during the year. Translation gains and losses are reflected in income when incurred.

(I) FINANCIAL INSTRUMENTS

The Company utilizes derivative financial instrument contracts such as forwards, futures, swaps and options to manage its exposure to petroleum and natural gas prices, the Canadian/US dollar exchange rate and interest rate fluctuations. Gains or losses from foreign exchange and commodity hedge contracts are recognized as part of petroleum and natural gas sales in the same period as the related production revenue. Amounts received or paid under interest rate swaps are recognized in interest expense as incurred. The fair values of these contracts are not reflected in the consolidated financial statements. The Company does not enter into derivative instruments for trading or speculative purposes.

The Company's policy is to formally designate each derivative financial instrument as a hedge of a specifically identified future revenue stream. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term to maturity, the notional amount, including the commodity price, exchange rate and interest rate basis of the instruments, all match the terms of the future revenue stream being hedged.

Realized and unrealized gains or losses associated with derivative financial instrument contracts that have been terminated or cease to be effective prior to maturity are deferred as other current, or non-current, assets or liabilities on the balance sheet, as appropriate and recognized in earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any realized or unrealized gain or loss on such derivative instrument is recognized in earnings.

(J) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation and impairment of petroleum property and equipment, and for site restoration and abandonment are based on estimates of reserves, future costs, petroleum and natural gas prices and other relevant assumptions. By their nature, these estimates and those related to the future cash flow used to assess impairment are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

(K) INCOME TAXES

The Company follows the liability method of accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period in which the change occurs.

(L) STOCK OPTION PLAN

The Company has a stock-based compensation plan consisting of a stock option plan that is described in note 10.

Options granted under the Company's employee stock option plan are issued at current market value of the Company's stock. The fair value of the options issued is estimated at the date of grant and the compensation expense recognized over the expected life of the option. Consideration paid to the Company on exercise of the stock option is credited to share capital.

(M) PER COMMON SHARE AMOUNTS

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that proceeds received from the exercise of in-the-money stock options and other dilutive instruments are used to purchase common shares at the average market price during the year.

2. Acquisition of Summit Resources Limited

On May 12, 2002, Paramount and Summit Resources Limited ("Summit") jointly announced that they had entered into an agreement pursuant to which Paramount would make an offer to purchase all of the issued and outstanding common shares of Summit for cash consideration of $7.40 per share or approximately $249.6 million, including acquisition costs. This transaction has been accounted for using the purchase method and is being accounted for as of the date of substantial completion of the acquisition of June 28, 2002.

The Company has finalized the purchase price equation for this acquisition. The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition:

Assets	
Accounts receivable	$ 13,997
Petroleum and natural gas properties	419,642
Goodwill	31,621
	465,260
Liabilities	
Accounts payable	21,947
Future income taxes	108,373
Debt	74,513
Other liabilities	10,865
	215,698
Net assets acquired	$ 249,562

3. Change in Accounting Policy

STOCK-BASED COMPENSATION AND OTHER STOCK-BASED PAYMENTS

The Canadian Institute of Chartered Accountants issued Handbook Section 3870, Stock-Based Compensation and Other Stock-Based Payments, which requires fair value accounting for all stock-based payments to non-employees, and for employees awards that are direct awards of stock, or call for settlement in cash or other assets, and for stock appreciation rights.

The Company adopted the fair-value method of accounting for stock options issued to employees and directors for fiscal 2003. For stock options, the fair-value based method has been applied prospectively, whereby compensation costs are recognized for all options granted or modified on or after January 1, 2003. Adoption of this accounting policy has resulted in an expense of $1.2 million ($0.02 per share) being recorded in the Company's consolidated financial statements for the year ended December 31, 2003. For share appreciation rights, the fair-value based method was applied retroactively without restatement in 2002. There was no impact on the 2003 consolidated financial statements (2002 – $0.5 million).

4. Disposition of Assets to Paramount Energy Trust

During the first quarter of 2003, the Company completed the formation and structuring of Paramount Energy Trust (the "Trust") through the following transactions:

(a) On February 3, 2003, Paramount transferred to the Trust natural gas properties in the Legend area of Northeast Alberta for net proceeds of $28 million and 9,907,767 units of the Trust.

(b) On February 3, 2003, Paramount declared a dividend-in-kind of $51 million, consisting of an aggregate of 9,907,767 units of the Trust. The dividend was paid to shareholders of Paramount's common shares of record on the close of business on February 11, 2003.

(c) On March 11, 2003, in conjunction with the closing of a rights offering by the Trust, Paramount disposed of additional natural gas properties in Northeast Alberta to Paramount Operating Trust for net proceeds of $167 million.

As the transfer of the Initial Assets and the Additional Assets (collectively the "Trust Assets") represented a related party transaction not in the normal course of operations involving two companies under common control, the transaction has been accounted for at the net book value of the Trust Assets as recorded in the Company. Details are as follows:

Natural gas properties	$ 244,433
Future income tax liability	4,070
Site restoration liability	(5,900)
Costs of disposition	10,430
Adjustment to retained earnings	(6,638)
Net proceeds on disposition	$ 246,395

In connection with the creation and financing of the Trust and the transfer of natural gas properties to the Trust, the Company incurred costs of approximately $10.4 million. These costs have been included as a cost of disposition.

During 2003, the Company disposed of a minor non-core property to the Trust. The related party transaction was accounted for at the net book value of the assets, with an adjustment to retained earnings of $0.3 million.

	2003		2002	
	Cost	**Accumulated Depletion and Depreciation**	Cost	Accumulated Depletion and Depreciation
Petroleum and natural gas properties	**$ 961,248**	**$ 296,904**	$ 1,263,544	$ 326,074
Gas plants, gathering systems and production equipment	**430,234**	**107,031**	670,769	214,655
Building	**8,542**	**445**	8,481	146
Other	**20,516**	**9,955**	18,575	8,533
	$ 1,420,540	**$ 414,335**	$ 1,961,369	$ 549,408
Net book value	**$ 1,006,205**		$ 1,411,961	

Capital costs associated with non-producing petroleum and natural gas properties totaling approximately $209 million (2002 – $367 million) are currently not subject to depletion.

For the year ended December 31, 2003, the Company expensed $36.6 million in dry hole costs (2002 – $120.1 million). A portion of the dry hole costs expensed related to prior year capital projects that were determined in the current year to have no future economic value.

For the year ended December 31, 2003, the Company recorded a provision of $10.4 million (2002 – $31.3 million) in respect of impairment of petroleum and natural gas properties.

For the year ended December 31, 2003, the Company recorded a provision of $4.5 million (2002 – $3.4 million) in respect of future site restoration and abandonment costs.

The consolidated financial statements include the Company's proportionate share of the assets and liabilities of its joint ventures as follows:

	2003	2002
Assets		
Current assets	**$ 5,116**	$ 1,278
Property, plant and equipment	**5,811**	8,520
	$ 10,927	$ 9,798
Liabilities and equity		
Current liabilities	**$ 8,421**	$ 9,239
Other liabilities	**4,284**	2,008
Deficit	**(1,778)**	(1,449)
	$ 10,927	$ 9,798
Revenues	**$ 11,594**	$ 2,591
Expenses	**$ 11,749**	$ 2,396
Net earnings (loss)	**$ (155)**	$ 195
Cash flow provided by (used in)		
Operating activities	**$ (1,564)**	$ 3,452
Financing activities	**$ 2,437**	$ 1,063
Investing activities	**$ (873)**	$ (4,515)

On November 13, 2003, Wilson Drilling Ltd. replaced its existing term loan facility with a new $6.3 million credit facility with a Canadian chartered bank. The credit facility is repayable in equal monthly installments of $131,250 plus interest. As at December 31, 2003, the facility had an effective interest rate of 4.67 percent. Wilson Drilling Ltd. also has a long-term capital lease on one of its drilling rigs with a Canadian chartered bank in the amount of approximately $3 million. The lease runs until August 2007 and has an imputed interest rate of 8.9 percent. The Company has provided a guarantee on the capital lease. Earnings attributed to services provided to the Company have been eliminated from the consolidated statements of earnings.

Shehtah-Wilson Drilling Partnership, a partnership in which the Company has a 99 percent interest, has a 10-year operating lease for two oilfield drilling rigs. The commitment associated with this lease is as follows:

Year	Lease Commitment
2004	$ 1,696
2005	1,696
2006	1,696
2007	1,696
2008	1,696
Thereafter	6,784
	$ 15,264

7. Bank Loans

As at December 31, bank loans was comprised of:

	2003	2002
Production/working capital facility (2002 – 7.5%)	$ –	$ 418,300
Drilling rig indebtedness – current interest rate of 6.00% (2002 – 6.82%)	1,138	3,071
Mortgage – current interest rate of 6.15%	312	270
Bridge facility – (2002 – 13%)	–	44,900
LIBOR advances – (2002 – 7.75%)	–	31,556
	$ 1,450	$ 498,097

The Company has letters of credit totaling $10.3 million (2002 – $13.3 million) outstanding with a Canadian Chartered Bank. These letters of credit reduce the amount available under the Company's working capital facility.

8. Long-term Debt

As at December 31, long-term debt was comprised of:

	2003	2002
US Senior Notes – interest rate of 7.875%	$ 226,887	$ –
Credit facility – current interest rate of 4.5%	60,350	–
Drilling rig indebtedness – current interest rate of 6.00% (2002 – 6.82%)	3,456	1,443
Mortgage – interest rate of 6.15%	6,418	6,730
	$ 297,111	$ 8,173

The Company issued US $175 million of 7 7/8 percent Senior Notes due 2010 on October 27, 2003. Interest on the notes is payable semi-annually, beginning in 2004. The Company may redeem some or all of the notes at any time after November 1, 2007 at redemption prices ranging from 100 percent to 103.938 percent of the principal amount, plus accrued and unpaid interest to the redemption date, depending on the year in which the notes are redeemed. In addition, the Company may redeem up to 35 percent of the notes prior to November 1, 2006 at 107.875 percent of the principal amount, plus accrued interest to the redemption date, using the proceeds of certain equity offerings. The notes are unsecured and rank equally with all of the Company's existing and future senior unsecured indebtedness.

The Company incurred $7.1 million of financing charges in 2003 related to the issuance of the senior notes. The financing charges are capitalized to other assets and amortized evenly over the term of the notes.

On October 27, 2003, the Company replaced its existing credit facility with a new $203 million committed revolving/non-revolving term facility with a syndicate of Canadian chartered banks. Borrowings under the facility bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 50 to 300 basis points, dependent on certain conditions. The revolving nature of the new facility expires on March 31, 2004. The Company has requested for an extension of the revolving credit facility of up to 364 days, subject to the approval of the lenders. To facilitate the documentation of this extension, the Company has agreed to amend the expiry date of the existing facility to April 30, 2004. To the extent that any lenders participating in the syndicate do not approve the 364 day extension, the amount due to those lenders will convert to a one-year non-revolving term loan with principal due in full on March 31, 2005. Advances drawn on the facility are secured by a first floating charge over all the assets of the Company.

The Company has an office building which was acquired as a result of the acquisition of Summit Resources Limited. The building is mortgaged at an interest rate of 6.15 percent over a term of 5 years ending December 31, 2007.

DISPOSITION OF ASSETS TO PARAMOUNT ENERGY TRUST

In the first quarter of 2003, the Company transferred certain natural gas assets in Northeast Alberta to the Trust, a related party. The transaction (see note 4), was accounted for at the net book value of the assets as recorded in the Company,

NOTE PAYABLE TO PARAMOUNT OIL AND GAS LTD.

In 2002, in order to complement existing funding for the acquisition of Summit, the Company secured a $33 million loan, with an effective interest rate during 2002 of 5.5 percent, from Paramount Oil and Gas Ltd., a related entity with a significant ownership interest in the Company. The loan was repaid on March 7, 2003.

AUTHORIZED CAPITAL

The authorized capital of the Company is comprised of an unlimited number of non-voting preferred shares without nominal or par value, issuable in series, and an unlimited number of common shares without nominal or par value.

ISSUED CAPITAL

Common Shares	Number	Consideration
Balance December 31, 2001	59,453,600	$ 189,320
Stock options exercised during the year	5,000	72
Expenses recognized in respect of stock-based compensation during the year	–	801
Balance December 31, 2002	59,458,600	$ 190,193
Stock options exercised during the year	710,000	10,317
Shares repurchased – at par	(74,000)	(236)
Balance December 31, 2003	60,094,600	$ 200,274

The Company instituted a Normal Course Issuer Bid to acquire a maximum of 5 percent of its issued and outstanding shares commencing May 15, 2003, and ending May 14, 2004. During 2003, 74,000 shares (2002 – nil) were purchased pursuant to the plan at an average price of $9.53 per share.

Subsequent to year-end, the Company re-purchased 701,300 common shares at an average price of $10.86 per share.

In February 2003, employees of the Company exercised 710,000 stock options for total consideration of $10.3 million.

STOCK OPTION PLAN

The Company has an Employee Incentive Stock Option plan (the "plan"). Under the plan, stock options are granted at the current market price on the date of issuance. Participants in the plan, upon exercising their stock options, may request to receive either a cash payment equal to the difference between the exercise price and the market price of the Company's common shares or common shares issued from Treasury. Irrespective of the participant's request, the Company may choose to only issue common shares. Cash payments made in respect of the plan are charged to general and administrative expenses when incurred. Options granted vest over four years and have a four and a half year contractual life.

As at December 31, 2003, 5.9 million shares were reserved for issuance under the Company's Employee Incentive Stock Option Plan, of which 3.6 million shares are outstanding, exercisable to September 30, 2008, at prices ranging from $8.91 to $12.02 per share.

The formation of the Trust (note 4) resulted in the Company re-pricing stock options. 941,500 stock options issued in 2001, the majority of which were at exercise prices of $14.50 and $13.35 per option, were re-priced to exercise prices of $10.22 and $9.07 per option, respectively.

Stock options	2003		2002	
	Average Grant Price	**Options**	Average Grant Price	Options
Balance, beginning of year	**$ 14.25**	**1,949,500**	$ 14.08	2,173,500
Granted	**9.66**	**2,998,000**	15.90	80,000
Exercised	**14.29**	**(791,000)**	12.98	(195,000)
Cancelled	**10.30**	**(524,500)**	14.23	(109,000)
Balance, end of year	**$ 9.64**	**3,632,000**	$ 14.25	1,949,500
Options exercisable, end of year	**$ 10.72**	**1,087,875**	$ 14.35	738,500

The following summarizes information about stock options outstanding at December 31, 2003:

Exercise Prices	**Number**	**Outstanding Weighted Average Contractual Life**	**Weighted Average Exercise Price**	**Exercisable Number**	**Exercisable Weighted Average Exercise Price**
$ 8.91 – 9.80	2,506,000	4	$ 9.02	309,375	$ 9.00
$ 10.01 – 12.02	1,126,000	2	$ 11.04	778,500	$ 11.40
Total	3,632,000	3	$ 9.64	1,087,875	$ 10.72

FAIR VALUES

The fair values of all common share options granted are estimated as at the grant date using the Black-Scholes option-pricing model. The weighted average fair values of the options granted during the year and the weighted average assumptions used in their determination are as noted below:

	2003	2002
Risk-free interest rate	**5.8%**	5.8%
Expected life	**4 years**	4 years
Expected volatility	**39%**	39%
Fair value per option	**$ 3.42**	$ 6.38

The Company recognized compensation costs related to stock options granted to employees of $1.2 million. The Company recognized no compensation costs related to stock options granted to employees in 2002. Had compensation costs for stock options granted to employees in 2002 been determined based on the fair value at the grant date of the awards, $49,000 would have been charged to earnings in 2002, for which there was no impact on earnings per share. Options granted prior to 2003 continue to be accounted for through pro-forma disclosure.

PER SHARE INFORMATION

Basic earnings per share are calculated based on a weighted average number of common shares of 60,098,447 (2002 – 59,457,737). There are no anti-dilutive options at December 31, 2003.

11 Income Taxes

The income tax provision differs from the expected income taxes obtained by applying the Canadian corporate tax rate to income before taxes as follows:

	2003	2002
Corporate tax rate	**40.67%**	42.14%
Calculated income tax recovery	**$ (23,044)**	$ (11,571)
Increase (decrease) resulting from:		
Non-deductible Crown charges, net of Alberta Royalty Tax Credit	**21,991**	10,449
Federal resource allowance	**(17,124)**	(29,958)
Federal and provincial income tax rate adjustment	**(30,257)**	(2,758)
Attributed Canadian Royalty Income recognized	**(5,228)**	–
Large Corporations Tax and other	**2,875**	9,150
Non-taxable portion of gain on sale of investments	**-**	(8,603)
Recognition of tax pools not previously recognized	**(3,343)**	–
Other	**(5,164)**	(4,474)
Income tax recovery	**$ (59,294)**	$ (37,765)

COMPONENTS OF FUTURE INCOME TAXES

The net future tax liability comprises:	2003	2002
Differences between tax base and reported amounts of depreciable assets	**$ 215,250**	$ 285,201
Provision for future site restoration	**(7,310)**	(7,255)
Other	**2,473**	1,909
	$ 210,413	$ 279,855

The Company's financial instruments included in the consolidated balance sheet are comprised of short-term investments, accounts receivable, accounts payable, shareholder loan, bank loans, long term debt and deferred revenue.

(A) FOREIGN EXCHANGE HEDGES

The Company has entered into the following currency index swap transactions, fixing the exchange rate on receipts of US $24.4 million for CDN $34.9 million over the next two years at CDN $1.4335. The US $/CDN $ closing exchange rate was 1.2965 as at December 31, 2003 (December 31, 2002 – 1.5776).

Year of settlement	US dollars	Weighted Average Exchange Rate
2004	$ 12,360	1.4333
2005	12,000	1.4337
	$ 24,360	1.4335

At December 31, 2003 the estimated fair value of these hedges based on the Company's assessment of available market information was a gain of $3.3 million (2002 – loss of $6.0 million).

(B) COMMODITY PRICE HEDGES

At December 31, 2003, the Company has entered into financial forward sales arrangements as follows:

AECO	Price	Term
10,000 GJ/d	$ 7.35	January 2004 – March 2004
10,000 GJ/d	$ 6.26	January 2004 – March 2004
10,000 GJ/d	$ 6.14	January 2004 – March 2004
20,000 GJ/d	$ 6.51	January 2004 – March 2004
10,000 GJ/d	$ 5.55	April 2004 – October 2004
10,000 GJ/d	$ 5.51	April 2004 – October 2004
WTI		
1,000 Bbl/d	US $ 24.07	May 2002 – April 2004
1,000 Bbl/d	(collar) US $ 25.00 – $ 30.25	January 2004 – December 2004

Had these financial contracts been settled on December 31, 2003, using prices in effect at that time, the mark to market before tax loss would have totaled $1.6 million (2002 – $28.7 million).

Subsequent to December 31, 2003, the Company entered into financial agreements as follows:

AECO	Price	Term
10,000 GJ/d	$ 5.81	April 2004 – October 2004
10,000 GJ/d	$ 5.86	April 2004 – October 2004
20,000 GJ/d	$ 5.80	April 2004 – October 2004
10,000 GJ/d	(collar) $ 5.25 – $ 6.80	April 2004 – October 2004
10,000 GJ/d	(collar) $ 5.25 – $ 6.75	April 2004 – October 2004

(C) FAIR VALUES OF FINANCIAL ASSETS AND LIABILITIES

Borrowings under bank credit facilities and the issuance of commercial paper are for short periods and are market rate based, thus, carrying values approximate fair value. Fair values for derivative instruments are determined based on the estimated cash payment or receipt necessary to settle the contract at year-end. Cash payments or receipts are based on discounted cash flow analysis using current market rates and prices available to the Company.

The fair values of other financial instruments, including accounts receivable, accounts payable, shareholder loan, bank loans and deferred revenue, approximate their carrying values due to the short-term maturity of those instruments.

The fair values of the mortgage and drilling rig indebtedness approximate their carrying values, as there have been no significant changes in long-term interest rates from the dates these liabilities were incurred to the balance sheet date.

The fair value of the long term debt approximate their carrying values, as the debt has been translated into Canadian dollars at exchange rates in effect at the balance sheet date, and there have been no significant changes in long-term interest rates from the dates these liabilities were incurred to the balance sheet date.

(D) CREDIT RISK

The Company is exposed to credit risk from financial instruments to the extent of non-performance by third parties, and non-performance by counterparties to swap agreements. The Company minimizes credit risk associated with possible non-performance by financial instrument counterparties by entering into contracts with only highly rated counterparties and controls third party credit risk with credit approvals, limits on exposures to any one counterparty, and monitoring procedures. The Company sells production to a variety of purchasers under normal industry sale and payment terms. The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal credit risks.

(D) INTEREST RATE RISK

The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact the Company's debts that have a floating interest rate. The Company had no interest rate swaps or hedges at December 31, 2003.

13. Change in Non-cash Working Capital

	2003	2002
Change in non-cash working capital:		
Short-term investments	**$ (283)**	$ (236)
Accounts receivable	**6,859**	(18,686)
Prepaid expenses	**1,829**	(5,893)
Deferred hedging loss	**-**	17,638
Accounts payable and accrued liabilities	**(26,958)**	48,312
Less working capital deficiency acquired (note 2)	**-**	(7,950)
	$ (18,553)	$ 33,185
Operating activities	**$ (33,381)**	$ 40,145
Investing activities	**14,828**	(6,960)
	$ (18,553)	$ 33,185

Certain changes in non-cash working capital which were incurred as a result of asset dispositions during the year have been excluded from the above amounts.

Amounts paid during the year related to interest and large corporations and other taxes were as follows:

	2003	2002
Interest paid	**$ 17,497**	$ 23,278
Large corporations and other taxes paid	**$ 2,395**	$ 20,447

CONTINGENCIES

The Company is party to various legal claims associated with the ordinary conduct of business. The Company does not anticipate that these claims will have a material impact on the Company's financial position.

The Company indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their service to the Company to the extent permitted by law. The Company has acquired and maintains liability insurance for its directors and officers.

COMMITMENTS

As at December 31, 2003, the Company had the following commitments related to the operating lease for the building and pipeline commitments.

Year	2003
2004	$ 25,695
2005	23,925
2006	21,889
2007	21,889
2008	21,889
Thereafter	153,421
	$ 268,708

During 2000, the Alberta Energy and Utilities Board issued a decision regarding the Surmont natural gas bitumen co-production issue. As a result of this decision, the Board ordered the shut-in of approximately 22 MMcf/d of the Company's production. On February 28, 2002, the Company and the Surmont Gas Producers entered into a Memorandum of Agreement with the Province of Alberta effective May 1, 2000. The Memorandum provided for compensation of approximately $85 million to be paid to the Surmont Gas Producers by the Alberta Crown in the form of reduced royalties, as well as the granting to the Province of Alberta by the Surmont Gas Producers of an 11 percent gross overriding royalty encompassing certain wells, land and leases affected by the shut-in order of May 1, 2000.

In 2002, the Company received approximately $46.4 million in the form of reduced royalties from the Province of Alberta as compensation for its proportionate share of the settlement. The cash settlement, net of the net book value of wells, lands and leases in the affected area of approximately $9 million, has been recorded in net earnings in 2002.

During 2002, the Company recorded gains on disposal of its investments in Peyto Exploration and Development Corp. and other short-term investments of $40.8 million.

Certain comparative figures have been reclassified to conform with the current year's financial statement presentation.

14. Reconciliation of Financial Statements to United States Generally Accepted Accounting Principles

The consolidated financial statements have been prepared in accordance with Canadian GAAP. Any differences in accounting principles as they pertain to the accompanying financial statements are not material except as described below. The application of US GAAP would have the following effects on the Company's historical net earnings (loss) as reported:

Year ended December 31	**2003**	2002
Net earnings for the year as reported	**$ 2,633**	$ 10,307
Adjustments, net of tax		
Forward foreign exchange contracts and other financial instruments (a)	**3,411**	(25,267)
Impairments and related change in depletion (c)	**6,762**	(15,138)
Depletion and depreciation (d)	**(1,734)**	
General and administrative (d)	**141**	–
Short-term investments (f)	**428**	
Net earnings (loss) for the year before changes in accounting policies - US GAAP (e)	**$ 11,641**	$ (30,098)
Change in accounting policy - asset retirement obligation (d)	**-**	(15,633)
Net earnings (loss) for the year – US GAAP	**$ 11,641**	$ (45,731)
Net earnings (loss) per common share before change in accounting policy – US GAAP (e)		
Basic	**$ 0.19**	$ (0.51)
Diluted	**$ 0.19**	$ (0.51)
Net earnings (loss) per common share – US GAAP (e)		
Basic	**$ 0.19**	$ (0.77)
Diluted	**$ 0.19**	$ (0.77)

The application of US GAAP would have the following effect on the balance sheet at December 31:

	2003		2002	
	As Reported	**US GAAP**	As Reported	US GAAP
Assets				
Short-term investments (f)	**$ 16,551**	**17,265**	$ 14,168	14,168
Assets held for sale (e)	**-**	**-**	–	193,899
Property, plant and equipment (c) (d) (e)	**1,006,205**	**1,022,366**	1,411,961	1,225,138
Liabilities				
Deferred hedging loss (gain) (a)	**-**	**1,726**	–	43,667
Provision for future site restoration and abandonment costs (d)	**21,114**	**59,301**	22,954	56,575
Deferred revenue (a)	**3,959**	**-**	7,804	7,804
Future income taxes (a) (b) (c) (d) (f)	**210,413**	**222,163**	279,855	253,971
Shareholders' equity				
Retained earnings	**$ 300,622**	**273,245**	$ 355,912	311,584

(a) Forward foreign exchange contracts and other financial instruments – The Company has designated, for Canadian GAAP purposes, its derivative financial instruments as hedges of anticipated revenue and expenses. In accordance with Canadian GAAP, payments or receipts on these contracts are recognized in income concurrently with the hedged transaction. The fair values of the contracts deemed to be hedges are not reflected in the financial statements.

For US purposes, the Company has adopted Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, Accounting for Derivative Instruments and Hedging Activities. With the adoption of this standard all derivative instruments are recognized on the balance sheet at fair value. The statement requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Management has not designated any of the currently held financial instruments as hedges for US GAAP purposes and accordingly these derivatives have been recognized on the balance sheet at fair value with the change in their fair value recognized in earnings.

Under US GAAP for the year ended December 31, 2003, additional income of $5.7 million (net of tax – $3.4 million) and for the year ended December 31, 2002, additional expense of $43.7 million (net of tax – $25.3 million) would have been recorded.

(b) Deferred income taxes – The Canadian liability method of accounting for income taxes is similar to the US SFAS No. 109 "Accounting for Income Taxes", which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. Pursuant to US GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted rates. For the years ended December 31, 2003 and 2002 this difference did not impact the Company's financial position or results of operations.

(c) Impairments – Under both US and Canadian GAAP, property, plant and equipment must be assessed for potential impairments. Under US GAAP, if the sum of the expected future cash flows (undiscounted and without interest charges) is less than the carrying amount of the asset, then an impairment loss (the amount by which the carrying amount of the asset exceeds the fair value of the asset) should be recognized. Fair value is calculated as the present value of estimated expected future cash flows. As disclosed in note 1, under Canadian GAAP, the impairment loss is the difference between the carrying value of the asset and its net recoverable amount (discounted). For the year ended December 31, 2003, no impairment charge would be recorded and a reduction in depletion expense of $11.3 million (net of tax – $6.8 million) would be recorded due to impairment charges recorded in fiscal 2002 under US GAAP. For the year ended December 31, 2002, an additional impairment charge of $49.0 million (net of tax – $28.3 million), and a reduction in depletion expense of $23.0 million (net of tax – $13.1 million) would have been recorded under US GAAP. The resulting differences in recorded carrying values of impaired assets result in further differences in depreciation, depletion and amortization expense in subsequent years.

The Canadian Institute of Chartered Accountants (the "CICA") has adopted a new standard that will eliminate this US/Canadian GAAP difference going forward.

(d) Asset retirement obligations – For US purposes, the Company has adopted SFAS No. 143, Accounting for Asset Retirement Obligations. Under US GAAP, legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of long-lived assets must be recognized at fair value in the period in which the liability is incurred. The fair value is added to the carrying amount of the associated asset. The liability is accreted at the end of each period through charges to operating expenses.

For the year ended December 31, 2003, the change results in an additional reduction to site restoration expense of $0.2 million (net of tax - $0.1 million) and an additional charge to depletion and depreciation of $2.9 million (net of tax - $1.7 million). The effect on the consolidated balance sheet is an increase in property, plant and equipment of $16.2 million and an increase of $38.2 million to the provision for future site restoration and abandonment costs.

For the year ended December 31, 2002, the cumulative impact results in an additional charge due to a change in accounting policy of $20.1 million (net of tax of $15.6 million). The cumulative effect on the consolidated balance sheet is an increase in property, plant and equipment of $36.4 million, an increase to site restoration liability of $33.6 million.

(e) Discontinued operations – Under US GAAP, the transaction resulting in the disposal of the Trust Assets to the Trust as described in note 4 would be accounted for as discontinued operations as the applicable criteria set out in SFAS 144, "Accounting for Impairment or Disposal of Long-lived Assets" had been met. Accordingly, the carrying value of the Trust Assets are separately presented in the consolidated balance sheet. Net income from discontinued operations for the year ended December 31, 2003, would have been $11.6 million (2002 – net loss $5.7 million), or $0.19 per basic and diluted common share (2002 – loss of $0.10 per basic and diluted common share).

(f) Short-term investments – Under US GAAP, equity securities that are bought and sold in the short term are classified as trading securities. Unrealized holding gains and losses related to trading securities are included in earnings as incurred. Under Canadian GAAP, these gains and losses are not recognized in earnings until the security is sold. As at December 31, 2003, the Company had unrealized holding gains of $0.7 million (net of tax – $0.4 million).

(g) Other comprehensive income – Under US GAAP, certain items such as the unrealized gain or loss on derivative instrument contracts designated and effective as cash flow hedges are included in other comprehensive income. In these financial statements, there are no comprehensive income items other than net earnings.

(h) Statements of cash flow – The application of US GAAP would not change the amounts as reported under Canadian GAAP for cash flows provided by (used in) operating, investing or financing activities, except that the consolidated statements of cash flow include, under investing activities, changes in working capital for items not affecting cash, such as accounts payable related to the non-cash elements of property and equipment reductions of $14,828 (2002 – additions of $6,960). This disclosure has been provided in order to disclose the aggregate costs related to such activities and to arrive at the cash amounts. This presentation is not permitted under US GAAP.

PARAMOUNT RESOURCES LTD.

Paramount
resources ltd.

ANNUAL INFORMATION FORM

Annual Information Form

Bbls	barrels
Bbl/d	barrels per day
Bcf	billion cubic feet
Bcfe	billion cubic feet of gas equivalent
Boe	barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet of gas equivalent
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MBbl	thousands of barrels
MMbtu	millions of British Thermal Units
Mboe	thousands of barrels of oil equivalent
Mboe/d	thousands of barrels of oil equivalent per day
MMcfe/d	million cubic feet of gas equivalent per day

Advisory Regarding Forward-looking Statements

This Annual Information Form contains forward-looking statements within the meaning of applicable securities laws. Forward-looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact. The forward-looking statements in this Annual Information Form include statements with respect to, among other things:

Paramount Resources Ltd.'s ("Paramount", "we", "our", or the "Company") acquisition strategy; our business strategy; our focus on our core areas; our intent to consolidate our position in our current core areas and our intent to grow new core areas; our plan to continue focusing on finding and developing long-life reserves; the funding sources of our development and exploration projects; the funding sources of our acquisitions; our increasing profitability resulting from our focus on natural gas production; reserve estimates; oil and natural gas prices; our future net revenue; our future costs; inflation estimates; our future development costs; our abandonment and reclamation costs, our exploration, development and drilling plans, production estimates, our capital budget and the allocation thereof; our status as a cash tax payer and the forward-looking statements contained in our Management's Discussion and Analysis, which is incorporated herein by reference.

Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on them because we can give no assurance that such expectations will prove to have been correct. There are many factors that could cause forward-looking statements not to be correct, including known and unknown risks and uncertainties inherent in the Company's business. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate and interest rate fluctuations, availability of services and supplies, market competition, uncertainties in the estimates of reserves, the timing of development expenditures, production levels and the timing of achieving such levels, the Company's ability to replace and expand oil and gas reserves, the sources and adequacy of funding for capital investments, future growth prospects and current and expected financial requirements of the Company, the cost of future dismantlement and site restoration, the Company's ability to enter into or renew leases, the Company's ability to secure adequate product transportation, changes in environmental and other regulations, the Company's ability to extend its debt on an ongoing basis and general economic conditions.

The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement. We undertake no obligation to update our forward-looking statements except as required by law.

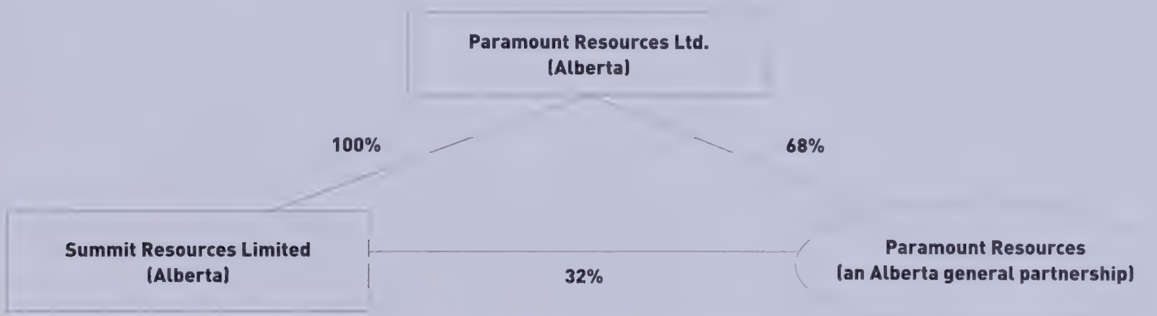
Corporate Structure

Paramount was incorporated under the laws of the Province of Alberta on February 14, 1978. On December 18, 1978, the Company became a public company listed on the Alberta Stock Exchange.

On November 30, 1984, Paramount was listed on the Toronto Stock Exchange ("TSX") and is currently part of the S&P/TSX Composite Index (Oil & Gas Producers sub index).

The head and principal office of the Company is located at Suite 4700, 888 – 3rd Street S.W., Calgary, Alberta T2P 5C5.

The diagram below illustrates Paramount's intercorporate relationships. The diagram below does not include all of the subsidiaries and partnerships of Paramount. The aggregate assets and aggregate revenues of the subsidiaries and partnerships excluded did not exceed 10 percent of the total consolidated assets and total consolidated revenues of Paramount as at and for the year ended December 31, 2003, respectively. The Company's assets are held both directly and indirectly through its principal subsidiaries and Paramount Resources, a general partnership in which the Company has a 68 percent interest and Summit Resources Limited has the remaining 32 percent interest.



Paramount Resources Ltd. is an independent Canadian energy company involved in the exploration, development, production, processing, transportation and marketing of natural gas and its byproducts and crude oil. The Company commenced operations as a public company listed on the Alberta Stock Exchange on December 18, 1978, with a successful initial public offering that raised $4.7 million and a share exchange with a private company, Paramount Oil & Gas Ltd., for certain crude oil and natural gas assets with book value of $341,000.

THREE-YEAR HISTORY

In 2001, Paramount's operations grew through exploration, development and acquisition of oil and gas properties. The Company incurred net capital expenditures of $287.4 million. As part of its expenditures on acquisitions, Paramount closed the Kaybob North sour gas plant acquisition adding approximately 12 MMcf/d of natural gas and 400 Bbl/d of liquids, establishing a majority interest and operatorship in the gas plant. In addition, Paramount drilled a historical high of 196 gross (158.7 net) wells with a gross 92 percent success rate.

In 2002, Paramount's operations were highlighted by the concurrent announcement of its intentions to acquire all the issued and outstanding shares of Summit Resources Limited ("Summit") and to create a new royalty trust that would hold substantially all of Paramount's Northeast Alberta natural gas assets. In July 2002, Paramount completed the acquisition of Summit for cash consideration of $249.6 million. The acquisition increased the Company's proven and probable natural gas reserves at January 1, 2003, by approximately 91 Bcf and proven and probable oil and natural gas liquids reserves by approximately 12 MMBbl. Production was initially increased by approximately 50 MMcf/d of natural gas and 5,000 Bbl/d of oil and natural gas liquids.

During 2002, Paramount also received $46.4 million in the form of reduced royalties as compensation from the Government of Alberta relating to the shut-in of approximately 22 MMcf/d (net) of gas over bitumen production at the Surmont area in May 2000. Paramount has retained legal ownership of the mineral rights and their associated gas reserves, subject to an 11 percent gross overriding royalty held by the Crown.

In 2003, Paramount completed the disposition of its Northeast Alberta natural gas assets to the newly formed Paramount Energy Trust ("PET" or "Trust") with the following transactions:

(a) On February 3, 2003, Paramount transferred to PET assets in the Legend area of Northeast Alberta for net proceeds of $28 million and 9,907,767 units of the Trust, which was paid to Paramount on March 11, 2003.

(b) On February 3, 2003, Paramount declared a dividend-in-kind of an aggregate of 9,907,767 trust units of PET. The dividend was paid to holders of Paramount common shares of record on the close of business on February 11, 2003. The dividend was declared after PET received all regulatory clearances with respect to its final prospectus in Canada and its registration statement in the United States. The final prospectus and registration statement qualified and registered:

- (i) the dividend trust units;
- (ii) rights to purchase further trust units, which rights were issued to unitholders after the payment of the dividend; and
- (iii) the trust units issuable upon the exercise of the rights.

(c) On March 11, 2003, in conjunction with the closing of a rights offering by the Trust, Paramount disposed of additional assets in Northeast Alberta to Paramount Operating Trust for net proceeds of $167 million, including adjustments to the purchase price. The combined production of natural gas including the assets in the Legend area averaged 97 MMcf/d during 2002.

On October 1, 2003, the Company sold its Sturgeon Lake properties in the Grande Prairie area, including the associated oil batteries and gas plant, to an unrelated third party for proceeds of $54.0 million.

During 2003, the Company successfully executed a disposition program consisting of minor, non-core producing and non-producing properties for a total consideration of $71.2 million.

The Company's 2003 results reflect the overall impact of the disposition of its Northeast Alberta Natural Gas assets to the Trust as well as the disposition of the Sturgeon Lake assets and minor, non-core properties.

The Company issued US $175 million of 7 7/8 percent Senior Notes due 2010 on October 27, 2003. Interest on the notes is payable semi-annually, beginning in 2004. The Company may redeem some or all of the notes at any time after November 1, 2007, at redemption prices ranging from 100 percent to 103.938 percent of the principal amount, plus accrued and unpaid interest to the redemption date, depending on the year in which the notes are redeemed. In addition, the Company may redeem up to 35 percent of the notes prior to November 1, 2006, at 107.875 percent of the principal amount, plus accrued interest to the redemption date, using the proceeds of certain equity offerings. The notes are unsecured and rank equally with all of the Company's existing and future senior unsecured indebtedness.

Description Of Business

OVERVIEW

Paramount's principal properties are located primarily in Alberta, the Northwest Territories, British Columbia and Saskatchewan in Canada. We also have properties offshore on the east coast of Canada, and in Montana, North Dakota and California in the United States. In 2003, sales of natural gas accounted for approximately 78 percent of the Company's total production.

The Company's ongoing exploration, development and production activities are designed to establish new reserves of oil and natural gas and increase the productive capacity of existing fields. In order to optimize its net capacity and control costs, the Company increases ownership and throughput in existing plants as economic opportunities arise and occasionally disposes of lower working interest properties. Paramount strives to maintain a balanced portfolio of opportunities, increasing its working interest in low to medium risk projects and entering into joint venture arrangements on select high risk/high return exploration prospects.

Paramount also participates in the petroleum and natural gas industry through the focused acquisition of petroleum and natural gas assets within established core areas. This acquisition strategy focuses on long-term value including assets which will increase Paramount's current working interest. To take advantage of opportunities as they arise, the Company maintains a strong balance sheet which allows such acquisitions to be financed.

At December 31, 2003, approximately 80 percent of Paramount's proved and probable natural gas reserves were located in Alberta with the balance in British Columbia, the Northwest Territories, Saskatchewan, California, Montana and North Dakota. Oil and natural gas liquids reserves are 63 percent located in Alberta, with the remainder in Saskatchewan, the Northwest Territories, California, North Dakota and Montana. In 2003, Paramount operated 90 percent of its net producing natural gas wells and approximately 93 percent of its net producing crude oil wells.

Paramount has established core areas of production in Kaybob, Grande Prairie, Northwest Alberta, Liard, Northwest Territories, Northeast British Columbia, Southern Alberta, Southeast Saskatchewan, Montana and North Dakota. Paramount continues to explore actively for petroleum and natural gas reserves within these core areas, and outside them as well. The Company has also established opportunities for heavy oil exploration and development in Northeast Alberta. The development of new core areas ensures adequate supply for existing gas marketing contracts. These development plans can be accelerated within the limits of the Company's cash resources during times of favourable market conditions.

EMPLOYEES

At December 31, 2003, Paramount had 134 full-time head office employees and 60 full-time employees at field locations. The Company's compensation of full time employees includes a combination of salary, benefits and participation in either a stock option plan or a Company-assisted share purchase savings plan. Shares under the savings plan are purchased in the marketplace by the plan trustee.

BUSINESS STRATEGY

Our strategy is to maintain a balanced portfolio of opportunities, to grow our reserves and increase our production in our core areas while maintaining a large inventory of undeveloped acreage, and to selectively enter into joint venture arrangements for high risk/high return prospects. We intend to pursue this strategy through the following initiatives:

CONCENTRATE ON CORE AREAS

We currently operate in five core production areas that provide us with a balanced portfolio of exploration and development prospects. We expect to continue to increase our interests and operatorship when possible in these core areas in order to achieve low-risk growth and cost efficiencies in production. This focus has enabled us to develop expertise in the local geologies and techniques required to exploit hydrocarbons in these regions. In addition, our concentrated interests allow us to benefit from economies of scale and other efficiencies that could improve our gross operating margins.

FOCUS ON NATURAL GAS

We have extensive technical expertise and have achieved significant success in exploring for shallow and deep natural gas reservoirs. We plan to continue to focus on finding and developing long-life natural gas reserves. Our gross proved reserves based on forecast prices and costs as of December 31, 2003, were approximately 79 percent natural gas. We believe our focus on natural gas production should lead to increasing future profitability, as natural gas prices are anticipated to be strong in the future as a result of increasing North American demand exceeding naturally declining supply.

We plan to reinvest internally generated cash flow to fund our inventory of development and exploration projects. In addition, we seek to rationalize our undeveloped acreage base, adding to and consolidating our land position as we develop a growing inventory of future drilling locations. We have successfully completed and integrated a series of strategic acquisitions to: grow our reserves and production base, increase our inventory of undeveloped acreage and provide processing facilities for our production. Our acquisition strategy focuses on acquiring assets within our established core areas that will create long-term value, including assets that will increase our current working interests in such areas.

As of December 31, 2003, we operated approximately 90 percent of our net producing natural gas wells and approximately 93 percent of our net producing oil wells, and had an average working interest of approximately 59 percent in our undeveloped acreage. We intend to continue consolidating our position in our core areas in order to maximize operating efficiencies and maintain control over our ongoing capital programs. We also owned or controlled the infrastructure critical to approximately 58 percent of our production, which we believe will continue to be critical to the success of our full-cycle exploration program. This high level of ownership and control allows us to control the timing and methodology of ongoing exploration and development programs.

We have assembled a substantial portfolio of approximately 4.8 million gross (approximately 2.8 million net) acres of undeveloped acreage that we hold for drilling activities. In the future, we intend to further apply our technical expertise to develop this acreage portfolio and grow new core areas.

We plan to maintain financial flexibility to allow us to pursue our full-cycle exploration program in periods of low commodity prices, and to respond to opportunities for strategic acquisitions as they arise. We intend to fund our exploration program and strategic acquisitions using cash flow, proceeds from property dispositions, equity or debt financing, or a combination of these sources.

MAJOR PROPERTIES

The following is a summary of Paramount's major producing properties at December 31, 2003. Paramount's exploration efforts are primarily concentrated in Alberta, British Columbia, Saskatchewan, the Northwest Territories, Montana and North Dakota. The Company is focused on five core operating areas as described below. In this AIF, certain natural gas volumes have been converted to barrels of oil equivalent (Boe) on the basis of 6,000 cubic feet (Mcf) to one barrel (Bbl). Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. Reference to reserve estimates in the following property descriptions are based on the McDaniel and Associates Consultants Ltd. ("McDaniel") forecast prices and costs case.

Kaybob, located in central Alberta, Canada, is our largest producing core area, accounting for approximately 48 percent of our production for the year ended December 31, 2003. Production in the area for that period averaged 94.2 MMcfe/d or 15.7 MBoe/d in 2003: 79.5 MMcf/d natural gas and 2,451 Bbl/d crude oil and natural gas liquids. Our Kaybob area contains 171.4 Bcfe of proved reserves that are 83 percent natural gas weighted, and 27.7 Bcfe of probable reserves that are 82 percent natural gas weighted.

Paramount operates four natural gas plants in this core area. We have a sour gas plant at Kaybob North and three sweet gas plants at Kaybob 5-1, Two Creeks and Clover. These plants process approximately 64 percent of the natural gas produced from the Kaybob area. The Company operates one oil battery at Kaybob North. Third-party facilities process Paramount's gas at Pine Creek, Fox Creek and Kakwa.

This core area, located in northwest-central Alberta, Canada, was formerly called Sturgeon Lake/Mirage. In October 2003, the Sturgeon Lake property was sold. Remaining important properties in this area include Mirage, Saddle Hills, Sunset and Valhalla. Grande Prairie accounted for approximately 12 percent of our production for the year ended December 31, 2003. Production in this area averaged 23.0 MMcfe/d or 3.8 MBoe/d in 2003: 12.4 MMcf/d natural gas and 1,767 Bbl/d crude oil and natural gas liquids. Grande Prairie is weighted to natural gas with 26.9 Bcfe of proved reserves that are 78 percent natural gas, and 5.7 Bcfe of probable reserves that are 84 percent natural gas.

Paramount operates three compression facilities and one oil battery in the Grande Prairie area, all at the Mirage property. Approximately 40 percent of the area's total production is from these Company-operated facilities.

NORTHWEST ALBERTA

The Northwest Alberta Core Area, located in the extreme northwest corner of Alberta and in the Northwest Territories in Canada, accounted for approximately 13 percent of our production for the year ended December 31, 2003. Production in the area for that period averaged 25.0 MMcef/d or 4.2 MBoe/d in 2003: 22.3 MMcf/d natural gas and 448 Bbl/d of crude oil and natural gas liquids. Our Northwest Alberta area contains 58.8 Bcfe of proved reserves that are approximately 87 percent natural gas weighted, and 11.3 Bcfe of probable reserves that are 77 percent natural gas weighted.

The Company operates one sour gas plant at Bistcho Lake, which also processes gas from Cameron Hills in the Northwest Territories, and two sweet gas plants at East Negus and Assumption, near Rainbow Lake in northern Alberta. This operated gas production accounts for approximately 95 percent of the natural gas produced from this core area. We also operate an oil battery at Cameron Hills in the Northwest Territories. Natural gas at the Haro property is produced from a nearly 50 percent-owned third-party operated gas plant.

LIARD, NWT/NORTHEAST BRITISH COLUMBIA

The Liard, NWT/Northeast British Columbia Core Area, located in northern British Columbia and southwestern Northwest Territories in Canada, accounted for approximately six percent of our production for the year ended December 31, 2003. Production averaged 11.7 MMcfe/d or 1.9 MBoe/d in 2003: 11.6 MMcf/d natural gas and 9 Bbl/d crude oil and natural gas liquids. This area contains 15.1 Bcfe of proved reserves that are nearly 100 percent natural gas weighted and 9.0 Bcfe of probable reserves that are almost 100 percent natural gas weighted.

We operate two gas plants in Northeast British Columbia, at Tattoo and Maxhamish, and produce gas from two third–party operated facilities in Clarke Lake, British Columbia and Liard in the Northwest Territories.

SOUTHERN ALBERTA/SOUTHEAST SASKATCHEWAN/UNI

Southern Alberta/Southeast Saskatchewan/United States accounted for approximately 12 percent of our production for the year ended December 31, 2003. Contained in this core area are properties located in southern Alberta and southeast Saskatchewan in Canada, and Montana and North Dakota in the United States. Production in the area for that period averaged 24.3 MMcfe/d or 4.1 MBoe/d in 2003: 9.5 MMcf/d natural gas and 2,457 Bbl/d crude oil and natural gas liquids. This area contains 32.1 Bcfe of proved reserves that are approximately 36 percent natural gas weighted, and 4.3 Bcfe of probable reserves that are 36 percent natural gas weighted.

The Company operates four gas plants in the Southern Core Area, one at Sylvan Lake and three at the Chain properties, all in Alberta. Approximately half the natural gas produced in the Southern Alberta/Southeast Saskatchewan/United States area comes from these operated plants. Crude oil is produced from 11 Company-operated batteries, four in Saskatchewan, four in Alberta, one in Montana and two in North Dakota. Approximately 67 percent of the total oil production came from Company-operated batteries.

COMPETITIVE CONDITIONS

The petroleum and natural gas industry is highly competitive. Paramount competes with numerous other participants in the search for and acquisition of crude oil and natural gas properties and in the marketing of these commodities. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and reserves. Our competitive position depends upon our geological, geophysical and engineering expertise and our financial resources. In addition, successful reserve replacement in the future will depend not only on the further development of present properties, but also on the ability to select and acquire suitable prospects for exploratory drilling and development.

Paramount has firm service for most of its natural gas production as opposed to interruptible allocations on pipeline systems. The Company closely monitors the daily production from all of its plants to ensure that contractual obligations will be met. Balancing contractual commitments, natural gas sales are directed to those markets where the Company believes prices will be best.

Paramount actively monitors and reviews its crude oil and natural gas liquids sales arrangements to ensure that our netbacks are optimized.

ENVIRONMENTAL PROTECTION

The oil and natural gas industry is governed by environmental requirements under both Canadian and United States federal, provincial, state and municipal laws, regulations and guidelines, which restrict and/or prohibit the release or emission of pollutants and regulate the storage, handling, transportation and disposal of various substances produced or utilized in association with oil and gas industry operations.

Paramount has in place an Environmental, Health and Safety Committee comprised of three directors of the Company. The tenet of the Company's Environmental Policy is as follows: **Paramount is committed to protecting the environment, to maintaining public health and safe workplaces and to compliance with all applicable laws, regulations and standards. Paramount will do all that it reasonably can to ensure that sound environmental, health and safety practices are followed in all of its operations and activities.**

The Environmental, Health and Safety Committee is guided by a specific set of principles to ensure that this policy is supported. These principles apply to all employees of Paramount and are designed to make certain that all applicable environmental laws, regulations and standards are complied with. The Company monitors all activities and makes reasonable efforts to ensure that companies who provide services to Paramount will operate in a manner consistent with its environmental policy.

DISCLOSURE OF RESERVES DATA

The majority of Paramount's assigned reserves of crude oil, natural gas liquids and natural gas are located in western Canada, with the remaining reserves in the United States, specifically California, Montana and North Dakota. For 2003, all reserves were determined through independent engineering evaluations completed by McDaniel, which were prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in National Instrument 51-101 – Standards of Disclosure for Oil & Gas Activities ("NI 51-101") and the COGE Handbook. The report was prepared effective December 31, 2003, (the "McDaniel Report"). The following tables set forth information relating to Paramount's working interest share of reserves, net reserves after royalties and present worth values as at December 31, 2003. The reserves are reported using constant price and costs as well as forecast prices and costs. Columns may not add in the following tables due to rounding.

All evaluations of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of Paramount's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas liquids and natural gas reserves may be greater than or less than the estimates provided herein.

Paramount's Audit Committee, comprised of independent board members, reviews the qualifications and appointment of the independent qualified reserves evaluator. The Audit Committee also reviews the procedures for providing information to the evaluator. All booked reserves are based upon annual evaluation by the independent qualified reserves evaluator.

In accordance with the requirements of NI 51-101, the Report on Reserves Data By Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Reserves Data and Other Information in Form 51-101F3 are attached as Appendices A and B hereto, respectively.

RESERVES DATA – CONSTANT PRICE AND COSTS

The following table summarizes the reserves evaluated at December 31, 2003, using constant price and costs.

Reserves Category	Natural Gas Gross (Bcf)	Natural Gas Net (Bcf)	Light and Medium Crude Oil Gross (MBbl)	Light and Medium Crude Oil Net (MBbl)	Natural Gas Liquids Gross (MBbl)	Natural Gas Liquids Net (MBbl)
Canada						
Proved						
Developed producing	174.5	138.0	3,759	3,468	3,263	2,268
Developed non-producing	47.6	40.6	529	519	542	397
Undeveloped	18.6	17.5	437	409	111	92
Total proved	240.7	196.1	4,725	4,396	3,916	2,757
Probable	87.6	65.8	1,278	1,181	479	332
Total proved plus probable Canada	328.3	261.9	6,003	5,577	4,395	3,089
United States						
Proved						
Developed producing	0.5	0.4	1,974	1,516	2	2
Developed non-producing	–	–	–	–	–	–
Undeveloped	–	–	–	–	–	–
Total proved	0.5	0.4	1,974	1,516	2	2
Probable	0.1	0.1	143	110	3	3
Total proved plus probable US	0.6	0.5	2,117	1,626	5	5
Total Company						
Total proved	241.2	196.5	6,699	5,911	3,918	2,759
Total probable	87.7	65.9	1,421	1,292	482	335
Total reserves	328.9	262.4	8,120	7,203	4,400	3,094

NET PRESENT VALUE OF FUTURE NET REVENUE – CONSTANT PRICE [illegible]

The following tables summarize the net present values of future net revenue attributable to reserves evaluated at December 31, 2003, for the constant price and costs case. The net present values are reported before income tax and after income tax at discount values of 0 percent, 5 percent, 10 percent, 15 percent and 20 percent.

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at					After Income Taxes Discounted at				
Reserves Category ($ millions)	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Canada										
Proved										
Developed producing	809.5	681.6	594.7	531.3	482.6	697.5	591.7	519.2	466.0	425.1
Developed non-producing	183.3	132.9	103.9	85.6	73.1	126.1	90.2	69.6	56.6	47.8
Undeveloped	75.4	44.6	29.3	20.9	15.9	57.4	33.6	21.9	15.4	11.5
Total proved	1,068.2	859.1	727.9	637.8	571.6	881.0	715.5	610.7	538.0	484.4
Probable	353.6	242.2	175.9	134.2	106.5	236.3	160.7	115.9	87.7	69.0
Total proved plus probable Canada	1,421.8	1,101.3	903.8	772.0	678.1	1,117.3	876.2	726.6	625.7	553.4
United States										
Proved										
Developed producing	30.5	24.9	21.0	18.2	16.2	30.5	24.9	21.0	18.2	16.2
Developed non-producing	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)
Undeveloped	–	–	–	–	–	–	–	–	–	–
Total proved	30.2	24.6	20.8	18.0	16.0	30.2	24.6	20.8	18.0	16.0
Probable	2.9	2.1	1.7	1.4	1.1	2.9	2.2	1.7	1.4	1.1
Total proved plus probable US	33.1	26.7	22.5	19.4	17.1	33.1	26.8	22.5	19.4	17.1
Total Company										
Total proved	1,098.4	883.7	748.7	655.8	587.6	911.2	740.1	631.5	556.0	500.4
Total probable	356.5	244.3	177.6	135.6	107.6	239.2	162.9	117.6	89.1	70.1
Total reserves	1,454.9	1,128.0	926.3	791.4	695.2	1,150.4	903.0	749.1	645.1	570.5

The following table summarizes the total undiscounted future net revenue evaluated at December 31, 2003, using constant price and costs.

Reserves Category ($ millions)	**Revenue**	**Royalties** [1]	**Operating Costs**	**Development Costs**	**Well Abandonment Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Proved	1,843.5	382.0	308.5	22.7	31.9	1,098.4	187.2	911.2
Proved plus probable	2,437.5	520.3	397.4	33.0	31.9	1,454.9	304.5	1,150.4

(1) Royalties includes crown royalties, freehold royalties, overriding royalties, mineral taxes, Saskatchewan Capital Surcharge, net profit interest payments and are net of Alberta Royalty Tax Credit.

The following table summarizes the net present value of future net revenue by production group evaluated at December 31, 2003, using constant price and costs, discounted at 10 percent.

Reserves Category ($ millions)	**Production Group**	**Future Net Revenue Before Income Taxes** (discounted at 10%)
Proved	Natural gas	591.4
	Light and medium crude oil	88.9
	Natural gas liquids	63.9
Proved plus probable	Natural gas	745.1
	Light and medium crude oil	105.8
	Natural gas liquids	70.9

RESERVES DATA – FORECAST PRICES AND COSTS

The following table summarizes the reserves evaluated at December 31, 2003, using McDaniel's forecast prices and costs.

	Natural Gas		**Light and Medium Crude Oil**		**Natural Gas Liquids**	
Reserves Category	**Gross** (Bcf)	**Net** (Bcf)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBbl)	**Net** (MBbl)
Canada						
Proved						
Developed producing	174.9	138.3	3,755	3,484	3,269	2,281
Developed non-producing	47.6	40.6	529	520	543	397
Undeveloped	18.6	17.5	437	412	111	93
Total proved	241.1	196.4	4,721	4,416	3,923	2,771
Probable	87.7	65.8	1,271	1,184	479	334
Total proved plus probable Canada	328.8	262.2	5,992	5,600	4,402	3,105
United States						
Proved						
Developed producing	0.5	0.4	1,971	1,513	2	2
Developed non-producing	–	–	–	–	–	–
Undeveloped	–	–	–	–	–	–
Total proved	0.5	0.4	1,971	1,513	2	2
Probable	0.1	0.1	143	111	3	3
Total proved plus probable US	0.6	0.5	2,114	1,624	5	5
Total Company						
Total proved	241.7	196.8	6,692	5,929	3,925	2,773
Total probable	87.7	65.9	1,414	1,295	482	337
Total reserves	329.4	262.7	8,106	7,224	4,407	3,110

NET PRESENT VALUE OF FUTURE NET REVENUE – FORECAST PRICES AND COSTS

The following table summarizes the net present values of future net revenue attributable to reserves evaluated at December 31, 2003, for the McDaniel's forecast prices and costs case. The net present values are reported before income tax and after income tax at discount values of 0 percent, 5 percent, 10 percent, 15 percent and 20 percent.

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at					After Income Taxes Discounted at				
Reserves Category ($ millions)	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20**
Canada										
Proved										
Developed producing	636.9	545.8	483.0	436.7	400.7	583.5	504.2	449.0	408.0	376.0
Developed non-producing	140.1	101.7	79.9	66.3	57.2	95.0	69.4	54.8	45.8	39.8
Undeveloped	59.2	34.7	22.6	15.9	11.9	43.1	25.0	16.1	11.2	8.3
Total proved	836.2	682.2	585.5	518.9	469.8	721.6	598.6	519.9	465.0	424.1
Probable	267.9	184.9	135.2	103.6	82.6	180.4	126.4	93.6	72.5	58.4
Total proved plus probable Canada	1,104.1	867.1	720.7	622.5	552.4	902.0	725.0	613.5	537.5	482.5
United States										
Proved										
Developed producing	15.7	13.7	12.2	10.9	10.0	15.7	13.7	12.2	10.9	10.0
Developed non-producing	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)
Undeveloped	–	–	–	–	–	–	–	–	–	–
Total proved	15.4	13.4	11.9	10.7	9.8	15.4	13.4	11.9	10.7	9.8
Probable	1.6	1.3	1.0	0.9	0.7	1.6	1.3	1.0	0.9	0.7
Total proved plus probable US	17.0	14.7	12.9	11.6	10.5	17.0	14.7	12.9	11.6	10.5
Total Company										
Total proved	851.6	695.6	597.4	529.6	479.6	737.0	612.0	531.8	475.7	433.9
Total probable	269.5	186.2	136.2	104.5	83.3	182.0	127.7	94.6	73.4	59.1
Total reserves	1,121.1	881.8	733.6	634.1	562.9	919.0	739.7	626.4	549.1	493.0

TOTAL FUTURE NET REVENUE BY PRODUCTION GROUP — FORECAST PRICES AND COSTS

The following table summarizes the total undiscounted future net revenue evaluated at December 31, 2003, using McDaniel's forecast prices and costs.

Reserves Category ($ millions)	**Revenue**	**Royalties**[1]	**Operating Costs**	**Development Costs**	**Well Abandonment Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Proved	1,583.3	315.5	353.0	25.1	38.1	851.6	114.6	737.0
Proved plus probable	2,087.9	428.4	462.9	36.2	39.3	1,121.1	202.1	919.0

(1) Royalties includes crown royalties, freehold royalties, overriding royalties, mineral taxes, Saskatchewan Capital Surcharge, net profit interest payments and are net of Alberta Tax Royalty Credit.

The following table summarizes the net present value of future net revenue by production group evaluated at December 31, 2003 using McDaniel's forecast prices and costs, discounted at 10 percent.

Reserves Category ($ millions)	**Production Group**	**Future Net Revenue Before Income Taxes** (discounted at 10%)
Proved	Natural gas	483.4
	Light and medium crude oil	62.0
	Natural gas liquids	47.6
Proved plus probable	Natural gas	601.8
	Light and medium crude oil	74.5
	Light and medium crude oil and natural gas liquids	52.8

The following definitions form the basis of classification for reserves presented in the McDaniel Report:

(a) **Proved Reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(i) Developed Reserves

Those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production.
The developed category may be subdivided into producing and non-producing.

(ii) Developed Producing Reserves

Those reserves that are expected to be recovered from completion intervals open at the time of estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(iii) Developed Non-producing Reserves

Those reserves that either have not been on production or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(iv) Undeveloped Reserves

Those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

(b) **Probable Reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(c) **Gross Reserves** are defined as the reserves owned before deduction of any royalties.

(d) **Net Reserves** are defined as the gross reserves of the properties in which an interest is held, less all royalties and interests owned by others.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

The following tables summarize the prices and costs used in the McDaniel Report in calculating the net present value of future net revenue attributable to reserves.

	US Henry Hub Gas Price	Alberta Average Plantgate	WTI Crude Oil	Edmonton Light Crude Oil	Bow River Medium Crude Oil	Edmonton NGL Mix	Exchange Rate[1]
	(CDN$/MMbtu)	(CDN$/MMbtu)	(CDN$/Bbl)	(CDN$/Bbl)	(CDN$/Bbl)	(CDN$/Bbl)	(US$/CDN$)
2003	8.00	5.92	42.02	40.70	30.42	36.80	0.77

(1) Exchange rates used to generate the benchmark reference prices in this table.

	US Henry Hub Gas Price	Alberta Average Plantgate	WTI Crude Oil	Edmonton Light Crude Oil	Bow River Medium Crude Oil	Edmonton NGL Mix	Inflation Rates[1]	Exchange Rate[2]
	(US$/MMbtu)	(CDN$/MMbtu)	(US$/Bbl)	(CDN$/Bbl)	(CDN$/Bbl)	(CDN$/Bbl)	(%/year)	(US$/CDN$)
2004	5.00	5.65	29.00	37.70	27.70	27.90	2.00	0.75
2005	4.65	5.30	26.50	34.30	26.65	25.50	2.00	0.75
2006	4.30	4.95	25.50	33.00	26.24	24.50	2.00	0.75
2007	4.08	4.75	25.00	32.30	25.40	23.80	2.00	0.75
2008	3.97	4.60	25.00	32.30	25.26	23.70	2.00	0.75

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

RESERVE RECONCILIATION

	Production Group	
Reserve Category	**Natural Gas** (Bcf)	**Light and Medium Crude Oil & Natural Gas Liquids** (MBbl)
Proved	241.7	10,617
Probable	87.7	1,896
Total gross reserves	329.4	12,513

The following table sets forth the reconciliation of Paramount's gross reserves for the year ended December 31, 2003, as evaluated by McDaniel using forecast prices and costs. We have reconciled our reserves to January 1, 2003, proved plus 50 percent of probable reserves (established reserves). Gross reserves include working interest reserves before royalties .

	Natural Gas (Bcf)			**Light and Medium Crude Oil & Natural Gas Liquids** (MBbl)		
	Proved	**Probable**	**Total**	**Proved**	**Probable**	**Total**
January 1, 2003	446.5	86.1	532.6	17,545	2,650	20,195
Extensions and discoveries	52.3	11.2	63.5	1,428	251	1,679
Improved recovery	–	–	–	–	–	–
Technical revisions	(28.3)	12.6	(15.7)	(1,130)	(433)	(1,563)
Acquisitions	1.6	0.1	1.7	–	–	–
Dispositions	(174.6)	(22.3)	(196.9)	(4,609)	(572)	(5,181)
Economic factors	–	–	–	–	–	–
Production	(55.8)	–	(55.8)	(2,617)	–	(2,617)
December 31, 2003	241.7	87.7	329.4	10,617	1,896	12,513

	Production Group	
Reserve Category	**Natural Gas** (Bcf)	**Light and Medium Crude Oil & Natural Gas Liquids** (MBbl)
Proved	196.8	8,702
Probable	65.9	1,632
Total net reserves	262.7	10,334

The following table sets forth the reconciliation of Paramount's net reserves for the year ended December 31, 2003, as evaluated by McDaniel using forecast prices and costs. We have reconciled our reserves to January 1, 2003, proved plus 50 percent of probable reserves (established reserves). Net reserves include working interest reserves after royalties.

	Natural Gas (Bcf)			**Light and Medium Crude Oil & Natural Gas Liquids** (MBbl)		
	Proved	**Probable**	**Total**	**Proved**	**Probable**	**Total**
January 1, 2003	359.1	65.9	425.0	14,796	2,323	17,119
Extensions and discoveries	40.4	10.1	50.5	1,193	318	1,511
Improved recovery	–	–	–	–	–	–
Technical revisions	(19.0)	6.7	(12.3)	(1,306)	(487)	(1,793)
Acquisitions	1.4	0.3	1.7	5	1	6
Dispositions	(139.9)	(17.1)	(157.0)	(3,866)	(523)	(4,389)
Economic factors	–	–	–	–	–	–
Production	(45.2)	–	(45.2)	(2,120)	–	(2,120)
December 31, 2003	196.8	65.9	262.7	8,702	1,632	10,334

The following table sets forth the Company's reconciliation of after-tax future net revenue attributable to net proved reserves from January 1, 2003 to December 31, 2003, using the constant price and costs case, discounted at 10 percent.

Period/Factor ($ millions)	
Present value of future net revenue at January 1, 2003	$ 938.0
Sale of production, net of production costs and royalties	(180.6)
Net change in prices, production costs and royalties related to future production	109.0
Revisions of estimates in development costs incurred	(15.3)
Changes in estimated future development costs	1.5
Extensions, improved recoveries and discoveries	151.4
Acquisitions of reserves	4.0
Dispositions of reserves	(510.9)
Net change resulting from revisions in quantity estimates	(88.9)
Accretion of discount	122.3
Net change in income taxes	101.0
Present value of future net revenue at December 31, 2003	$ 631.5

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

The following table summarizes the Company's gross proved undeveloped reserves for the most recent five financial years, using forecast prices and costs.

Product	**2003**	**2002**	**2001**	**2000**	**1999**
Natural gas (Bcf)	18.6	26.7	24.7	5.3	4.2
Light and medium crude oil (MBbl)	437	845	328	–	499
Natural gas liquids (MBbl)	111	165	–	–	18

These reserves are classified as proved undeveloped if they are expected to be recovered from new wells on previously undrilled acreage with untested reservoir characteristics, or they are reserves from existing wells that require major capital expenditure to bring them on production.

The following table summarizes the Company's gross probable undeveloped reserves for the most recent five financial years, using forecast prices and costs.

Product	2003	2002	2001	2000	1999
Natural gas (Bcf)	87.7	129.6	117.4	130.7	155.0
Light and medium crude oil (MBbl)	1,271	4,559	1,271	1,054	1,026
Natural gas liquids (MBbl)	479	741	357	217	162

These reserves are classified as probable undeveloped when analysis of drilling, geological, geophysical and engineering data does not demonstrate them to be proved under current technology and existing economic conditions; however, this analysis does suggest that there is a likelihood of their existence and future recovery.

FUTURE DEVELOPMENT COSTS

The following table describes the estimated future development costs deducted in the estimation of future net revenue. The costs are per reserve category and quoted for no discount and a discount rate of ten percent.

Reserve Category ($ millions)	2004E		2005E		2006E		2007E		2008E	
	0%	10%	0%	10%	0%	10%	0%	10%	0%	10%
Proved:										
Constant price case	8.7	8.3	1.8	1.6	1.0	0.8	5.1	3.6	–	–
Forecast price case	8.9	8.5	1.9	1.6	1.0	0.8	5.5	3.9	–	–
Proved and probable reserves:										
Constant price case	9.7	9.3	3.3	2.9	1.3	1.0	5.7	4.1	6.5	4.2
Forecast price case	9.9	9.5	3.4	3.0	1.4	1.1	6.2	4.4	7.2	4.7

We expect that funding for future development costs will come from the Company's cash flow, a properly managed debt funding program and, in some cases, equity issues.

OTHER OIL AND GAS INFORMATION

OIL AND GAS PROPERTIES AND WELLS

As at December 31, 2003, Paramount had an interest in 1,699 gross (1,086.4 net) producing and non-producing oil and natural gas wells as follows:

	Producing		Non-producing[1]	
As at December 31, 2003	Gross[2]	Net[3]	Gross	Net
Crude Oil Wells				
Alberta	184	121.1	74	43.3
Saskatchewan	61	43.3	19	12.2
Northwest Territories	5	4.5	4	3.0
Montana	22	17.1	3	2.5
North Dakota	38	21.0	7	3.8
Subtotal	310	207.0	107	64.8
Natural Gas Wells				
Alberta	760	515.3	393	252.1
British Columbia	24	9.6	21	9.5
Saskatchewan	1	–	1	0.3
Northwest Territories	12	5.8	34	19.3
Montana	23	1.8	10	0.5
California	1	0.1	2	0.3
Subtotal	821	532.6	461	282.0
Total	1,131	739.6	568	346.8

(1) "Non-producing" wells are wells which Paramount considers capable of production but which, for a variety of reasons including but not limited to a lack of markets and lack of development, cannot be placed on production at the present time.
(2) "Gross" wells means the number of wells in which Paramount has a working interest or a royalty interest that may be convertible to a working interest.
(3) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.

The following table sets forth Paramount's land position at December 31, 2003. The Company's holdings total 5,737,166 gross (3,386,216 net) acres. Approximately 83 percent of the Company's gross land holdings are considered undeveloped, and approximately 37 percent of the undeveloped land is located in Alberta.

(thousands of acres)	2003		2002	
	Gross	**Net**[2]	**Gross**	**Net**
Undeveloped Land				
Alberta	1,752	1,314	2,581	1,884
British Columbia	263	183	248	164
Saskatchewan	29	24	21	15
Northwest Territories	948	412	843	580
Montana, North Dakota	100	35	149	70
Other	1,664	832	1,664	832
Subtotal	4,756	2,800	5,506	3,545
Acreage Assigned Reserves				
Alberta	850	529	2,027	1,461
British Columbia	37	10	32	10
Saskatchewan	6	3	12	6
Northwest Territories	59	29	74	45
Montana, North Dakota	29	15	24	10
Subtotal	981	586	2,169	1,532
Total acres	5,737	3,386	7,675	5,077

(1) "Gross" acres means the total acreage in which Paramount has a working interest, or a royalty interest that may be converted to a working interest.
(2) "Net" acres means the number of acres obtained by multiplying the gross acres by Paramount's working interest therein.

As of December 31, 2003, the Company had 665,947 (328,969 net) acres of undeveloped lands that were due to expire in 2004. Of this total, 17,600 (11,789 net) acres of undeveloped lands due to expire in 2004 have had dry and abandoned wells drilled on them. The other 648,347 (317,180 net) acres have not been tested as of December 31, 2003. 10,880 (8,960 net) acres of land that were due to expire in 2004 have been written off and expensed on the Company's income statement for the year ended December 31, 2003, as the Company has no further intention to explore on or develop these leases.

The Company's future commitments as at December 31, 2003, to sell natural gas and oil and natural gas liquids are set forth at note 12 of the Company's financial statements included in the Company's annual report, which information is incorporated by reference herein.

As at December 31, 2003, the Company had 1,112.4 net wells capable of production for which it expected to incur abandonment and reclamation costs.

The Company's estimates of abandonment and reclamation costs, net of estimated salvage value, for surface leases, wells, facilities and pipelines, undiscounted and discounted at 10 percent, are $58.2 million and $38.8 million, respectively. The future net revenue disclosed in the Annual Information Form based on the McDaniel Report does not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The McDaniel Report deducted $39.3 million (undiscounted) and $17.6 million (10 percent discount) for abandonment and reclamation costs for wells only in estimating the future net revenue disclosed in this Annual Information Form.

The Company does not expect to pay any material amounts with respect to abandonment and reclamation costs in the next three financial years.

Based on the current tax regime, and the Company's current structure and anticipated level of operations, we are not expected to be cash taxable in 2004, and estimate that the Company may become cash taxable by 2005.

COSTS INCURRED

The following table summarizes the costs incurred by Paramount for property acquisitions, exploration and development costs.

Cost Type ($ millions)	2003	Q4	Q3	Q2	Q1
Acquisitions (corporate and property)					
Proved properties	$ 0.9	$ 1.7	$ (0.8)	$ –	$ –
Unproved properties	22.3	9.8	5.1	5.2	2.2
Exploration	34.7	9.6	4.2	8.2	12.7
Development (including facilities)	166.8	65.1	26.9	37.3	37.5
Total	$ 224.7	$ 86.2	$ 35.4	$ 50.7	$ 52.4

EXPLORATION AND DEVELOPMENT ACTIVITY

The following table summarizes the results of Paramount's drilling activity for each of the last two fiscal years. The working interest in certain of these wells may change after payout.

	2003		2002	
	Gross[1]	**Net**[2]	**Gross**	**Net**
Development Wells[3]				
Gas	135	90.0	76	56.3
Oil	13	10.3	5	3.1
Standing/service	–	–	1	1.0
Dry	7	3.6	7	4.0
Subtotal	155	103.9	89	64.4
Exploratory Wells[4]				
Gas	45	30.7	38	27.4
Oil	3	2.1	4	3.6
Dry	8	2.2	4	4.0
Subtotal	56	35.0	46	35.0
Total wells	211	138.9	135	99.4
Success rate	93%	93%	92%	92%

[1] "Gross" wells means the number of wells in which Paramount has a working interest or a royalty interest that may be converted to a working interest.
[2] "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.
[3] "Development" well is a well drilled within or in close proximity to a discovered pool of petroleum or natural gas.
[4] "Exploratory" well is a well drilled either in search of a new and as yet undiscovered pool of petroleum or natural gas or with the expectation of significantly extending the limit of a pool that is partly discovered.

The total capital budget for 2004 is estimated at $240 million. Much of the activity in 2004 will occur in the Kaybob and Grande Prairie producing core areas with plans to complete the downspacing drilling programs initiated in the second half of 2003. Exploration activity continues in all of the core areas as well as the Colville Lake property in the Northwest Territories. The following table describes the estimated capital budget per core area:

Area ($ millions)	**2004E**
Kaybob	$ 101
Grande Prairie	50
Northwest Alberta	24
Liard/Northeast British Columbia	24
Southern Alberta	26
Heavy oil	4
Land and other	11
Total	$ 240

The following table summarizes the total estimated production for 2004 using constant price and costs.

	Estimated Production – Constant Price and Costs	
	Proved	**Proved plus Probable**
Canada		
Natural gas (MMcf)	50,219	52,619
Light and medium crude oil (MBbls)	1,058	1,131
Natural gas liquids (MBbls)	778	806
United States		
Natural gas (MMcf)	147	152
Light and medium crude oil (MBbls)	272	274
Natural gas liquids (MBbls)	2	2

The following table summarizes the total estimated production for 2004 using forecast prices and costs.

	Estimated Production – Forecast Prices and Costs	
	Proved	**Proved plus Probable**
Canada		
Natural gas (MMcf)	50,226	52,617
Light and medium crude oil (MBbls)	1,058	1,131
Natural gas liquids (MBbls)	778	806
United States		
Natural gas (MMcf)	147	152
Light and medium crude oil (MBbls)	272	274
Natural gas liquids (MBbls)	2	2

The following tables summarize daily sales volume results for Paramount on a quarterly and annual basis for 2003 and 2002, respectively.

	2003	**Q4**[1]	**Q3**	**Q2**	**Q1**
SALES – Canada					
Produced gas (MMcf/d)	152.1	140.5	135.1	141.2	192.4
Light and medium crude oil (Bbls/d)	4,040	3,267	4,067	4,342	4,498
Natural gas liquids (Bbls/d)	2,080	1,772	2,316	2,009	2,218
SALES – United States					
Produced gas (MMcf/d)	0.7	0.4	0.7	0.8	0.8
Light and medium crude oil (Bbls/d)	1,024	838	1,036	1,075	1,149
Natural gas liquids (Bbls/d)	25	–	42	39	27
SALES – Total					
Produced gas (MMcf/d)	152.8	140.9	135.8	142.0	193.2
Light and medium crude oil (Bbls/d)	5,064	4,105	5,103	5,417	5,647
Natural gas liquids (Bbls/d)	2,105	1,772	2,358	2,048	2,245

	2002[2]	**Q4**	**Q3**	**Q2**	**Q1**
SALES – Canada					
Produced gas (MMcf/d)	240.9	261.8	258.3	231.3	211.4
Light and medium crude oil (Bbls/d)	3,213	4,638	4,653	1,246	2,274
Natural gas liquids (Bbl/d)	1,835	2,668	1,991	1,390	1,271
SALES – United States					
Produced gas (MMcf/d)	0.5	0.8	1.0	0.1	0.1
Light and medium crude oil (Bbls/d)	593	1,209	1,139	1	3
Natural gas liquids (Bbl/d)	22	37	49	2	–
SALES – Total					
Produced gas (MMcf/d)	241.4	262.6	259.3	231.4	211.5
Light and medium crude oil (Bbls/d)	3,806	5,847	5,792	1,247	2,277
Natural gas liquids (Bbl/d)	1,857	2,705	2,040	1,392	1,271

(1) The Alberta Securities Commission released NI 51-101 in 2003, with an effective date of September 30, 2003. NI 51-101 requires all reported petroleum and natural gas production to be measured in marketable quantities, with adjustments for heat content included in the commodity price reported. The Company has adopted NI 51-101 prospectively. As such, fourth quarter natural gas production volumes are measured in marketable quantities, with adjustments for heat content and transportation reflected in the reported natural gas price.

(2) Six-month production volumes with respect to properties acquired in the Summit acquisition have been averaged over 12 months.

The following tables summarize the average netbacks on a quarterly and annual basis for 2003 and 2002, respectively.

	Net Product Price Results – 2003				
	2003	Q4[1]	Q3	Q2	Q1
Produced Gas ($/Mcf)					
Price, net of transportation and selling	5.99	5.14	5.74	5.90	6.85
Royalties	(1.13)	(0.55)	(1.30)	(1.14)	(1.43)
Operating costs[2]	(1.03)	(1.26)	(1.19)	(0.95)	(0.80)
Netback excluding hedge	3.83	3.33	3.25	3.81	4.62
Hedge	(0.83)	0.25	(0.72)	(1.09)	(1.52)
Netback including hedge	3.00	3.58	2.53	2.72	3.10
Total Conventional Oil ($/Bbl)					
Price, net of transportation and selling	39.19	35.19	37.83	38.30	44.28
Royalties	(7.30)	(6.44)	(6.64)	(7.09)	(8.77)
Operating costs[2]	(9.79)	(10.81)	(11.07)	(9.88)	(7.76)
Netback excluding hedge	22.10	17.94	20.12	21.33	27.75
Hedge	(3.92)	(4.47)	(3.32)	(2.30)	(5.64)
Netback including hedge	18.18	13.47	16.80	19.03	22.11
Natural Gas Liquids ($/Bbl)					
Price, net of transportation and selling	36.06	37.94	33.55	33.35	39.73
Royalties	(7.92)	(7.13)	(6.97)	(7.78)	(9.71)
Operating costs[2]	(7.43)	(11.45)	(7.70)	(6.30)	(4.94)
Netback	20.71	19.36	18.88	19.27	25.08

	Net Product Price Results – 2002				
	2002	Q4	Q3	Q2	Q1
Produced Gas ($/Mcf)					
Price, net of transportation and selling	3.53	4.94	2.59	4.06	2.35
Royalties	(0.68)	(0.94)	(0.60)	(0.72)	(0.40)
Operating costs[2]	(0.79)	(0.79)	(0.64)	(0.98)	(0.78)
Netback excluding hedge	2.06	3.21	1.35	2.36	1.17
Hedge	0.55	(0.48)	1.18	0.41	1.20
Netback including hedge	2.61	2.73	2.53	2.77	2.37
Total Conventional Oil ($/Bbl)					
Price, net of transportation and selling	37.80	36.90	40.20	39.95	32.76
Royalties	(7.70)	(7.03)	(9.36)	(7.05)	(5.52)
Operating costs[2]	(8.50)	(5.86)	(9.98)	(9.63)	(10.93)
Netback excluding hedge	21.60	24.01	20.86	23.27	16.31
Hedge	(0.82)	(1.11)	(1.03)	–	–
Netback including hedge	20.78	22.90	19.83	23.27	16.31
Natural Gas Liquids ($/Bbl)					
Price, net of transportation and selling	29.85	34.16	29.44	28.77	22.33
Royalties	(5.88)	(6.51)	(6.86)	(5.08)	(3.76)
Operating costs[2]	(6.57)	(5.42)	(7.31)	(6.93)	(7.45)
Netback	17.40	22.23	15.27	16.76	11.12

(1) The Alberta Securities Commission released NI 51-101 in 2003, with an effective date of September 30, 2003. NI 51-101 requires all reported petroleum and natural gas production to be measured in marketable quantities, with adjustments for heat content included in the commodity price reported. The Company has adopted NI 51-101 prospectively. As such, forth quarter natural gas production volumes are measured in marketable quantities, with adjustments for heat content and transportation reflected in the reported natural gas price.

(2) Operating costs include all costs related to the operation of wells, facilities and gathering systems. Processing revenue has been deducted from these costs.

The following table summarizes production volumes from Paramount's major producing properties for 2003 and 2002 and reflects the dispositions to the Trust.

Production Volume	**2003**	**2002**
Natural Gas (MMcf)		
Kaybob	29,024	31,937
Grande Prairie	4,522	2,554
Northwest Alberta	8,140	11,106
Liard, NWT/Northeast British Columbia	4,235	4,468
Southern Alberta/Southeast Saskatchewan/United States	3,483	1,971
Northeast Alberta	5,914	35,382
Non-core	442	696
Total	55,760	88,114
Light and Medium Crude Oil (MBbl)		
Kaybob	354	284
Grande Prairie	531	424
Northwest Alberta	133	–
Liard, NWT/Northeast British Columbia	–	–
Southern Alberta/Southeast Saskatchewan/United States	825	595
Non-core	5	86
Total	1,848	1,389
Natural Gas Liquids (MBbl)		
Kaybob	540	552
Grande Prairie	114	70
Northwest Alberta	30	14
Liard, NWT/Northeast British Columbia	3	4
Southern Alberta/Southeast Saskatchewan/United States	72	37
Non-core	10	1
Total	769	678

Selected Consolidated Financial and Operating Information

ANNUAL FINANCIAL INFORMATION

($ thousands except per share amounts)[1]

Year ended December 31	2003	2002	2001
Revenues – Including Hedges	$ 381,847	$ 473,942	$ 528,373
Expenses			
Royalties, net of ARTC	82,512	74,444	99,706
Operating	81,193	86,067	61,045
Interest[2]	19,756	23,943	19,291
General and administrative[3]	18,684	15,870	12,346
Lease rentals	3,574	4,552	4,319
Bad debt expense	5,977	–	–
Current income taxes and other	2,875	9,150	27,729
Cash Flow from Operations	167,276	259,916	303,937
Per share – basic	2.78	4.37	5.11
Per share – diluted	2.77	4.36	5.11
Depreciation and depletion	163,413	169,433	105,433
Dry hole costs	36,600	120,058	8,944
Net earnings	2,633	10,307	118,902
Per share – basic	0.04	0.17	2.00
Per share – diluted	0.04	0.16	2.00
Balance Sheet Information			
Capital expenditures – net	(144,978)	494,535	287,354
Proceeds from property sales	371,601	5,042	5,183
Working capital/(deficiency), excluding bank and shareholder loans	(9,143)	(15,973)	25,902
Total assets	1,147,848	1,526,786	1,176,323
Total debt	298,561	539,270	316,600
Shareholders' equity	501,642	546,105	535,384
Share Information			
Weighted average number of common shares outstanding (thousands)	60,098	59,458	59,454
Market price			
High	$ 16.95	$ 17.60	$ 18.75
Low	$ 8.51	$ 13.00	$ 12.00

(1) All per share amounts are calculated using average number of shares outstanding, except dividends paid per share which are based upon actual shares outstanding at time of dividend declaration.
(2) Net of non-cash interest expense.
(3) Net of non-cash general and administrative expenses.

DIVIDENDS

Paramount has not paid a cash dividend in the last three fiscal years. Future payments will be dependent upon the financial requirements of the Company to reinvest earnings, the financial condition of the Company and other factors which the Board of Directors of the Company may consider appropriate.

On February 3, 2003, Paramount declared a dividend-in-kind of an aggregate of 9,907,767 trust units of PET. Paramount received these trust units, in addition to $28 million in net proceeds as consideration for the transfer of the Legend assets to PET. The trust units were deemed to have a total value of $51 million (approximately $0.85 per share of Paramount, or $5.15 per trust unit).

Management's Discussion and Analysis for the year ended December 31, 2003, is presented in the Company's annual report and is incorporated by reference herein.

The common shares of Paramount are listed on the TSX under the trading symbol 'POU'.

The management of the Company is provided by four officers, two of whom currently also serve as directors. There are nine non-management directors to complete the Board of Directors. The names, position with Paramount and principal occupation of each of the officers and directors and the year each director was first elected or appointed a director can be found in the Management Information and Proxy Circular dated March 23, 2004, which information is incorporated by reference herein. The municipality of residence of each of the executive officers and directors is Calgary, Alberta, with the exception of Messrs. Jungé and Knott whose municipalities of residence are Jenkintown, Pennsylvania, and Syosset, New York, respectively.

The term of office for each director of the Company is from the date of the annual meeting at which the director is elected or appointed until the annual meeting next following or until his successor is elected or appointed. The current Board of Directors was nominated and elected at the Annual Meeting of the Shareholders held on June 26, 2003. The Board of Directors has an Audit Committee which consists of Messrs. Gorman, MacInnes, Roy and Thomson; a Compensation Committee which consists of Messrs. C. H. Riddell, Roy and MacInnes; a Corporate Governance Committee which consists of Messrs. Gorman, Jungé, MacInnes, Roy and Thomson and an Environmental, Health and Safety Committee which consists of Messrs. MacInnes, Roy and Wylie.

As at December 31, 2003, the directors and officers of the Company as a group beneficially owned 32,276,985 common shares, representing 53.74 percent of the 60,094,600 then issued and outstanding common shares of Paramount.

Certain directors and officers of Paramount are also directors and/or officers and/or significant shareholders of other companies engaged in the oil and gas business generally and which, in certain cases, own interests in oil and gas properties in which Paramount holds, or may in the future hold, an interest. As a result, situations may arise where such individuals have a conflict of interest. Such conflicts of interest will be resolved in accordance with Paramount's governing corporate statute, the Business Corporations Act (Alberta) (the "ABCA"), and Paramount's internal policies respecting conflicts of interest. The ABCA requires that a director or officer of a corporation who is party to a material contract or proposed material contract with the corporation, or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the corporation, disclose in writing to the corporation or request to have entered into the minutes of meetings of directors the nature and extent of the director's or officer's interest; and, if a director, that he or she not vote on any resolution to approve the contract, except in certain circumstances. The ABCA also requires that a corporation's directors and officers act honestly and in good faith with a view to the best interest of the corporation. Paramount's internal policies respecting conflicts of interest require that directors and officers of Paramount avoid putting themselves in a conflict of interest position and, if such a position arises, that disclosure of such position be made so that Paramount can approve or disapprove such position, with disapproved conflict of interest positions requiring immediate cessation by the director or officer.

Additional information, including directors' and officers' remuneration, principal holders of Paramount's securities, options to purchase securities, and interests of insiders in material transactions, where applicable, is contained in Paramount's Management Information and Proxy Circular dated March 23, 2004, relating to the 2004 Annual General and Special Meeting to be held on June 2, 2004, in Calgary, Alberta. Additional financial information is contained in the Company's comparative consolidated financial statements for the year ended December 31, 2003.

When the securities of Paramount are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities, Paramount will, upon request to the President as listed below, provide to any person the following information:

(a) One copy of the Company's Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

(b) One copy of the audited consolidated financial statements of Paramount for its most recently completed financial year for which financial statements have been filed together with the accompanying report of the auditor and one copy of the most recent interim financial statements of Paramount that have been filed, if any, for any period after the end of its most recently completed financial year;

(c) One copy of the information circular of Paramount in respect of its most recent annual meeting of shareholders that involved the election of directors; and

(d) One copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (a) to (c) above.

At any other time, Paramount will, upon request to the President as listed below, provide to any person one copy of any of the documents referred to in (a), (b) and (c) above, provided Paramount may require the payment of a reasonable charge if the request is made by a person or corporation who is not a security holder of Paramount.

For additional copies of this Annual Information Form or any of the materials listed in the preceding paragraphs, please contact:

Paramount Resources Ltd.
4700 Bankers Hall West
888 – 3rd Street S.W.
Calgary, Alberta, Canada T2P 5C5
Telephone: (403) 290-3600
Facsimile: (403) 262-7994

Attention:
James H.T. Riddell
President and Chief Operating Officer

or

Bernard K. Lee
Chief Financial Officer

McDaniel
& ASSOCIATES CONSULTANTS LTD.
Oil & Gas Reservoir Evaluations

March 18, 2004

Paramount Resources Ltd.
4700, 888 – 3rd Street S.W.
Calgary, Alberta
T2P 5C5

Attention: The Board of Directors of Paramount Resources Ltd.

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator of Paramount Resources Ltd. (the "Company")

Dear Sir:

To the Board of Directors of Paramount Resources Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2003. The reserves data consists of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

Suite 2200, Bow Valley Square 3, 255 - 5th Avenue S.W., Calgary, Alberta T2P 3G6
Tel: (403) 262-5506 Fax: (403) 233-2744 Email: mcdaniel@mcdan.com Website: www.mcdan.com

Paramount Resources Ltd.
March 18, 2004
Page 2

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2003, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management.

			Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator	**Description and Preparation Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates	December 31, 2003	Canada/ U.S.A.	-	733,620	-	733,620

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

P. A. Welch, P. Eng.
Executive Vice President

Calgary, Alberta
Date: March 18, 2004

Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Paramount Resources Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and
(ii) the related estimated future net revenue;

(b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and
(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the Board of Directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Audit Committee has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved;

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
(b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Clayton H. Riddell
Chief Executive Officer

Bernard K. Lee
Chief Financial Officer

Alistair S. Thompson
Director

John B. Roy
Director

March 23, 2003

Corporate Information

Officers

C. H. Riddell
Chairman of the Board and Chief Executive Officer

B. K. Lee
Chief Financial Officer

J. H. T. Riddell
President and Chief Operating Officer

C. E. Morin
Corporate Secretary

L. M. Doyle
Corporate Operating Officer

C. G. Folden
Corporate Operating Officer

J. S. McDougall
Corporate Operating Officer

G. W. P. McMillan
Corporate Operating Officer

J. B. Williams
Corporate Operating Officer

L. A. Friesen
Assistant Corporate Secretary

Directors

C. H. Riddell(3)
Chairman of the Board and
Chief Executive Officer
Paramount Resources Ltd.

J. H. T. Riddell
President and
Chief Operating Officer
Paramount Resources Ltd.

J. C. Gorman(1) (4)
Business Executive
Calgary, Alberta

D. Jungé, C.F.A(4)
Chairman of the Board
Pitcairn Trust Company
Jenkintown, Pennsylvania

D. M. Knott
General Partner
Knott Partners, L.P.
Syosset, New York

W. B. MacInnes, Q.C.(1) (2) (3) (4)
Barrister & Solicitor
Counsel, Gowling Lafleur Henderson, LLP
Calgary, Alberta

V. S. A. Riddell
Business Executive
Calgary, Alberta

S. L. Riddell Rose
President and
Chief Operating Officer
Paramount Energy Trust

J. B. Roy(1) (2) (3) (4)
Independent Businessman
Calgary, Alberta

A. S. Thomson(1) (4)
President
Touche, Thomson & Yeoman
Investment Consultants Ltd.
Calgary, Alberta

B. M. Wylie(2)
Business Executive
Calgary, Alberta

(1) Member of Audit Committee
(2) Member of Environmental, Health and Safety Committee
(3) Member of Compensation Committee
(4) Member of Corporate Governance Committee

Head Office

4700 Bankers Hall West
888 Third Street S.W.
Calgary, Alberta
Canada T2P 5C5
Telephone: (403) 290-3600
Facsimile: (403) 262-7994
www.paramountres.com

Consulting Engineers

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Bankers

Bank of Montreal
Calgary, Alberta

Canadian Imperial Bank of Commerce
Calgary, Alberta

The Bank of Nova Scotia
Calgary, Alberta

UBS AG Canada Branch
Toronto, Ontario

Registrar and Transfer Agent

Computershare Investor Services Canada
Calgary, Alberta
Toronto, Ontario

Stock Exchange Listing

The Toronto Stock Exchange
("POU")

Annual and Special Meeting

Shareholders are cordially invited to attend the Annual and Special Meeting to be held June 2, 2004, at 3:30 p.m.
Calgary Petroleum Club
McMurray Room
319 Fifth Avenue S.W.
Calgary, Alberta

Abbreviations

Bbls	barrels
Bbl/d	barrels per day
Bcf	billion cubic feet
Bcfe	billion cubic feet of gas equivalent
Boe	barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet of gas equivalent
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MBbl	thousands of barrels
MMbtu	millions of British Thermal Units
Mboe	thousands of barrels of oil equivalent
Mboe/d	thousands of barrels of oil equivalent per day
MMcfe/d	million cubic feet of gas equivalent per day

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MAJOR PRODUCING PROPERTIES

The following table summarizes average production volumes from Paramount's major producing properties, for each of the last five fiscal years.

Natural Gas (MMcf/d)	2003	2002	2001	2000	1999
Kaybob	79.5	87.5	65.3	63.7	47.6
Grande Prairie	12.4	7.0	3.1	–	–
Northwest Alberta	22.3	30.4	29.2	26.1	14.0
Liard – Northeast BC/NWT	11.6	12.3	9.3	5.4	–
Southern	9.5	5.4	–	–	–
Northeast Alberta	16.2	96.9	108.7	119.0	153.6
Other	1.3	1.9	9.4	5.8	4.8
Total	152.8	241.4	225.0	220.0	220.0

Crude Oil and Liquids (Bbl/d)	2003	2002	2001	2000	1999
Kaybob	2,451	2,291	1,855	1,258	839
Grande Prairie	1,767	1,353	–	–	–
Northwest Alberta	448	35	–	–	–
Liard - Northeast BC/NWT	9	15	21	95	–
Southern	2,457	1,732	130	218	852
Other	37	237	159	–	163
Total	7,169	5,663	2,165	1,571	1,854

Total Production (Boe/d @ 6:1)	2003	2002	2001	2000	1999
Kaybob	15,704	16,874	12,738	11,875	8,772
Grande Prairie	3,831	2,520	517	–	–
Northwest Alberta	4,165	5,102	4,867	4,350	2,333
Liard - Northeast BC/NWT	1,942	2,065	1,571	995	–
Southern	4,048	2,632	130	218	852
Northeast Alberta	2,700	16,150	18,117	19,833	25,600
Other	240	555	1,725	967	964
Total	32,630	45,898	39,665	38,238	38,521

CAPITAL EXPENDITURES

($ millions)	2003	2002
Drilling	$ 123.4	$ 124.1
Seismic	8.5	9.3
Facilities and equipment	69.6	77.4
Land acquisitions	22.3	6.4
Summit acquisition	–	251.4
Property acquisitions	0.9	28.6
Other	1.9	2.3
	226.6	499.5
Property dispositions	(371.6)	(5.0)
Net capital expenditures	$ (145.0)	$ 494.5

CORE PRODUCING PROPERTIES

BALANCE SHEET INFORMATION

As at December 31 ($ millions)	2003	2002	Change (%)
Assets			
Current assets	$ 103.0	$ 114.8	(10)
Property and equipment (net)	1,006.2	1,412.0	(29)
Other assets	38.6	–	–
	$ 1,147.8	$ 1,526.8	(25)
Liabilities and Equity			
Current liabilities	$ 112.2	130.8	(14)
Bank loans	298.5	539.3	(45)
Future site restoration	21.1	23.0	(8)
Deferred revenue	4.0	7.8	(49)
Future income taxes	210.4	279.8	(25)
Shareholders' equity	501.6	546.1	(8)
	$ 1,147.8	$ 1,526.8	(25)

NET ASSET VALUE PER COMMON SHARE

As at December 31, 2003 ($ millions except per share amount)	
Discount rate	10%
Present value of appraised reserves [1,2]	$ 733.6
Market value of short-term investments	17.3
Fair market value of undeveloped land	98.2
Other assets [3]	98.8
Subtotal	947.9
Working capital deficiency [4]	(25.7)
Debt	(298.6)
Net asset value	$ 623.6
Net asset value per common share [5]	$ 10.38

(1) Proved plus probable, includes benefit of ARTC with no allowance for income tax.
(2) Based on Forecast Price Assumptions.
(3) Includes seismic, projects under evaluation and building (all at cost).
(4) Excludes short-term investments.
(5) Based on outstanding common shares of 60,094,600 at December 31, 2003.

CAPITAL STRUCTURE

The following table outlines Paramount's capital structure since 1999.

($ thousands)	2003	2002	2001	2000	1999
Debt	$ 298,561	$ 539,270	$ 316,600	$ 315,000	$ 268,819
Common share equity	201,020	190,193	189,320	189,320	199,320
Retained earnings	300,622	355,912	346,064	228,934	129,672
	$ 800,203	$ 1,085,375	$ 851,984	$ 733,254	$ 597,811

NET DEBT

At December 31 ($ thousands)	2003	2002
Current assets	$ 103,016	$ 114,825
Less accounts payable	112,159	130,798
Working capital deficiency	9,143	15,973
Debt	298,561	539,270
Net debt	$ 307,704	$ 555,243

ESTIMATED FUTURE PRE-TAX CASH FLOW

	Reserves Before Royalty		Present Value of Estimated Pre-tax Cash Flow Discounted at: (millions of dollars)	
	Gas (Bcf)	Oil/liquids (MBbl)	10%	15%
Proved	242	10,617	598	530
Probable	87	1,896	136	104
Total	329	12,513	734	634

The discounted net present values of the estimated pre-tax cash flow expected during the economic life of all reserves are based on estimates using escalating price assumptions at rates of 10 percent and 15 percent per annum compounded annually. They are calculated prior to the consideration of income taxes but include ARTC, and are not to be construed as representing the fair market value of properties. The fair market value of the properties and such net present values will depend upon the subjective considerations inherent to each property.

KEY RATIOS

The following key ratios to "fundamental analysis" have been calculated to accompany the Cash Flow Reconciliation.

- Cash Flow per Share
- Share Price to Cash Flow Multiple
- Debt to Cash Flow Ratio
- Debt to Equity Ratio
- Earnings per Share
- Rate of Return on Shareholders' Equity

Per share amounts for 2003 utilize the weighted average number of common shares outstanding of 60,098,447.

Cash Flow
Paramount calculates its cash flow;
- net of all lease rentals of both producing and non-producing properties
- net of all cash general and administrative costs, none of which are capitalized
- net of all marketing costs which are currently expensed
- net of all interest expenses, none of which are capitalized

Net Earnings
Paramount further calculates its net earnings;
- net of dry hole costs
- net of geological and geophysical costs

CASH FLOW RECONCILIATION

($ millions) December 31	2003	2002	2001	2000	1999
Gross revenue[1]	381.8	473.9	528.4	391.5	211.7
Net royalties[2]	(82.5)	(74.4)	(99.7)	(80.6)	(37.6)
Net revenue	299.3	399.5	428.7	310.9	174.1
Expenses					
Operating	81.2	86.1	61.1	48.0	39.0
Cash G&A	18.7	15.9	12.4	9.7	8.6
Lease rentals	3.6	4.6	4.3	5.2	4.1
Cash interest	19.7	23.9	19.3	22.3	15.0
Bad debt expense	5.9	–	–	–	–
Current income taxes and other	2.9	9.1	27.7	2.3	1.6
Cash flow	167.3	259.9	303.9	223.4	105.8

(1) Includes gain on sale of investments
(2) Net of ARTC

CASH FLOW AND CASH FLOW/SHARE

Fiscal year	Cash Flow ($ 000s)	Trend[1]	Shares[2] (000s)	Cash Flow per Share ($)	Trend[1]
1999	105,830	100	57,529	1.84	100
2000	223,446	211	59,454	3.76	204
2001	303,937	287	59,454	5.11	278
2002	259,916	246	59,458	4.37	238
2003	167,276	158	60,098	2.78	151

(1) Trend with base year 1999, with a nominal value of 100.
(2) Weighted average shares outstanding.

SHARE PRICE TO CASH FLOW MULTIPLE

Fiscal Year	Share Price ($) Low	Share Price ($) High	Cash Flow per Share ($)	Multiple Low	Multiple High
1999	12.00	26.00	1.84	6.5x	14.1x
2000	10.50	20.00	3.76	2.8x	5.3x
2001	12.00	18.75	5.11	2.3x	3.7x
2002	13.00	17.60	4.37	3.0x	4.0x
2003	8.51	16.95	2.78	3.1x	6.1x

NET DEBT TO CASH FLOW RATIO

Fiscal year	Net Debt ($ 000s)	Cash Flow ($ 000s)	Debt/cash Flow Ratio	Flow Trend[1]
1999	252,382	105,830	2.4:1	100
2000	292,360	223,446	1.3:1	55
2001	290,698	303,937	1.0:1	40
2002	555,243	259,916	2.1:1	90
2003	307,704	167,276	1.8:1	77

(1) Trend with base year 1999 with a nominal value of 100.

DEBT TO EQUITY RATIO

Fiscal Year	Operating Debt ($ 000s)	Shareholders' Equity ($ 000s)	Debt/ Equity Ratio	Trend[1]
1999	268,819	328,992	0.82:1	100
2000	315,000	418,254	0.75:1	92
2001	316,600	535,384	0.59:1	72
2002	539,270	546,105	0.99:1	121
2003	298,561	501,642	0.60:1	73

(1) Trend with base year 1999 with a nominal value of 100.

EARNINGS PER SHARE

Paramount's earnings are net of dry hole costs, geological/ geophysical costs and all lease rentals.

Fiscal year	Net Earnings ($ 000s)	Trend[1]	Shares[2] (000s)	Net Earnings per Share ($)	Trend[1]
1999	28,683	100	57,529	0.50	100
2000	86,062	300	59,454	1.45	290
2001	118,902	415	59,454	2.00	400
2002	10,307	36	59,458	0.17	34
2003	2,633	9	60,098	0.04	8

(1) Trend with base year 1999 with a nominal value of 100.
(2) Weighted average shares outstanding.

RATE OF RETURN ON SHAREHOLDER'S EQUITY

Paramount has earned a weighted average after-tax rate of return of 13.5 percent as computed on a book basis, based upon the weighted average shareholders' equity invested over the past five years.

($ thousands)	2003	2002	2001	2000	1999
Net earnings	2,633	10,307	118,902	86,062	28,683
Weighted average Shareholders' equity	523,874	540,745	477,705	373,623	295,962
After-tax rate of return (%)	0.5	1.9	24.9	23.0	9.7

UNDEVELOPED LAND

(thousands of acres)	Gross	Net
Alberta	1,752	1,314
British Columbia	263	183
Saskatchewan	29	24
Northwest Territories	948	412
Montana, North Dakota	100	35
Other	1,664	832
Total Undeveloped Land	4,756	2,800
Net land	2003	2002
Proved	586	1,532
Undeveloped	2,800	3,545
Total net land	3,386	5,077
Appraised value of undeveloped land[1]	$ 98.2	$ 117.3

(1) Millions of dollars

Appraised value is an estimate of the fair market value of acreage based upon current analogous sales. Approximately 83 percent of the total net 2003 land inventory of 3.4 million acres is undeveloped.

OIL & GAS SALES AND GROSS PROFIT

This illustrates oil and gas sales since 1999 and converts the oil sales into barrels of equivalent (Boe) on an industry standard basis of one barrel of crude oil/liquids equals 6 Mcf of natural gas.

Fiscal year[1]	Oil & Gas Revenue (after hedging) ($ 000s)	Trend	Gas Production (MMcf)	Trend	Oil & Liquids Production (Bbl)	Trend	Average Price (after hedging) Gas ($)	Oil ($)	Barrel of Equivalent Production (MBoe)	Trend
1999	211,658	100	80,300	100	676,710	100	2.43	24.27	14,060	100
2000	391,470	185	80,520	100	574,986	85	4.59	37.80	13,995	100
2001	525,686	248	82,125	102	790,225	117	6.12	35.48	14,478	103
2002	431,001	204	88,111	110	2,066,995	305	4.08	34.64	16,753	119
2003	380,855	180	55,760	69	2,616,706	387	5.16	35.50	11,910	85

(1) Trend with base year 1999, with nominal value of 100

OPERATING CASH NETBACKS

Fiscal Year[1]	Royalties (net ARTC) ($ 000s)	($/Boe)	Trend	Operating Costs ($ 000s)	($/Boe)	Trend	Operating Cash Netback[2] ($ 000s)	($/Boe)	Trend	% of Revenue
1999	37,567	2.67	100	39,030	2.78	100	135,061	9.60	100	63.8
2000	80,541	5.75	215	47,974	3.43	123	262,955	18.79	196	67.2
2001	99,706	6.89	258	61,045	4.22	152	351,814	24.29	253	66.9
2002	74,444	4.44	166	86,067	5.14	185	266,618	15.92	166	61.9
2003	82,572	6.93	260	81,193	6.82	245	271,346	22.78	237	71.2

(1) Trend with base year 1999, with nominal value of 100.
(2) Operating cash netback = oil & gas and other revenue – royalty – operating cost.

REVENUE/EXPENSES/CASH FLOW NETBACK/NET EARNINGS

The table calculates revenue, expenses and net earnings converted into dollars per barrels of equivalent (Boe) (1 barrel = 6 Mcf).

($/Boe)	2003	2002	2001	2000	1999
Annual production (MBoe)	11,910	16,753	14,478	13,995	14,060
Gross revenue before commodity hedging	$ 36.61	$ 23.06	$ 35.20	$ 27.97	$ 15.05
Gain on sale of investments	(0.08)	2.44	0.20	–	–
Royalties	(6.93)	(4.44)	(6.89)	(5.75)	(2.67)
Operating costs	(6.82)	(5.14)	(4.22)	(3.43)	(2.78)
Operating netback	22.78	15.92	24.29	18.79	9.60
Commodity hedging (loss)	(4.47)	2.79	1.09	–	–
Cash general and administrative	(1.57)	(0.95)	(0.85)	(0.69)	(0.61)
Bad debt expense	(0.50)	–	–	–	–
Cash interest	(1.66)	(1.43)	(1.33)	(1.59)	(1.07)
Lease rentals	(0.30)	(0.27)	(0.30)	(0.37)	(0.29)
Current income tax	–	–	(1.73)	–	–
Large corporation tax and other	(0.24)	(0.55)	(0.19)	(0.16)	(0.11)
Cash flow netback	14.04	15.51	20.98	15.98	7.52
Non-cash general and administrative	(0.10)	(0.02)	–	–	–
Non-cash interest	(0.01)	–	–	–	–
Depletion and depreciation	(13.72)	(10.11)	(7.28)	(3.61)	(3.34)
Provision for future site restoration and abandonment	(0.37)	(0.21)	(0.17)	(0.12)	(0.09)
Surmont compensation	–	2.23	–	–	–
Gain (loss) on sale of properties	(0.31)	–	(0.11)	0.05	0.16
Dry hole costs	(3.07)	(7.17)	(0.62)	(0.50)	(0.74)
Write-down of petroleum and natural gas properties	(0.87)	(1.87)	–	–	–
Geological and geophysical	(0.71)	(0.56)	(0.74)	(0.48)	(0.17)
Unrealized foreign exchange gain (loss) on US debt	0.13	–	–	–	–
Future income taxes (recovery)	5.22	2.80	(3.87)	(5.14)	(1.31)
Net earnings	$ 0.23	$ 0.60	$ 8.19	$ 6.18	$ 2.03
Net earnings trend[1]	11	30	403	304	100

(1) Trend with base year 1999, with nominal value of 100.

HISTORICAL SUMMARY

	2003	2002	2001	2000	1999
Gas production (MMcf/d)	152.8	241.4	225.0	220.0	220.0
Crude oil and liquids production (Bbl/d)	7,169	5,663	2,165	1,571	1,854
Gas proved reserves (Bcf)	241.7	446.5	437.7	518.1	594.7
Crude oil and liquids proved reserves (MBbl)	10,617	17,545	6,339	4,709	6,264
Total proved and probable reserves (MMBoe) 6:1	67.4	125.9	101.9	115.5	133.8
Cash flow ($ millions)	$ 167.3	$ 259.9	$ 303.9	$ 223.4	$ 105.8
Cash flow per share (basic)	$ 2.78	$ 4.37	$ 5.11	$ 3.76	$ 1.84
Net earnings ($ millions)	$ 2.6	$ 10.3	$ 118.9	$ 86.1	$ 28.7
Net earnings per share (basic)	$ 0.04	$ 0.17	$ 2.00	$ 1.45	$ 0.50

Paramount resources ltd.

ANALYST SUPPLEMENT

This handbook has been prepared by Paramount Resources Ltd. to address the special information needs of the investment community and the sophisticated investor. The handbook provides detailed performance data and key ratios. For additional information please contact:

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J.H.T. (Jim) Riddell, President and Chief Operating Officer
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CORPORATE PROFILE

Paramount Resources Ltd. is a Canadian energy company with its revenue derived primarily from natural gas sales. The Company explores for, develops, produces and markets natural gas, crude oil and natural gas liquids. Paramount has an aggressive, focused exploration and development strategy, concentrated on acquiring land and establishing reserves throughout the Western Canadian Sedimentary Basin.

- 25 years old
- 194 employees (134 head office, 60 field)
- Listed on the Toronto Stock Exchange; symbol "POU"
- Part of the S&P/TSX Composite Index
- 60.1 million shares outstanding at December 31, 2003
- Market capitalization: $628 million (December 31, 2003)

Year	Cash Flow	Basic per Share	Earnings	Basic per Share
2001	$ 303.9 million	$ 5.11	$ 118.9 million	$ 2.00
2002	$ 259.9 million	$ 4.37	$ 10.3 million	$ 0.17
2003	$ 167.3 million	$ 2.78	$ 2.6 million	$ 0.04

Average number of common shares outstanding for 2003 was 60.1 million.

UNIQUE TRAITS

- 78 percent of 2003 production is natural gas.
- "Successful efforts" accounting policy results in conservative net earnings.
- High management ownership (54 percent).
- Successful full cycle exploration and development creates shareholder value.
- Proven performance record through 25 years of commodity price cycles.
- Exposure to high impact exploration plays in Colville Lake and Northeast Alberta bitumen project.

CONSOLIDATED EARNINGS & CASH FLOW DATA

($ millions except per share amounts)

Year ended December 31	2003	2002	Change (%)
Revenue			
Natural gas	$ 333.9	$ 311.4	7
Crude oil and liquids	100.1	72.8	38
Commodity hedging (loss) gain	(53.2)	46.8	–
Royalties, net of ARTC	(82.5)	(74.4)	11
(Loss) gain on investments	(1.0)	40.8	–
Other income (loss)	2.0	2.1	(5)
Net revenue	299.3	399.5	(25)
Expenses			
Operating	81.2	86.1	(6)
Surmont compensation	–	(37.3)	(100)
Interest	19.9	23.9	(17)
General and administrative	19.9	16.2	23
Dry hole	36.6	120.1	(70)
Geological and geophysical	8.5	9.3	(9)
Lease rentals	3.6	4.6	(22)
Site restoration	4.4	3.4	29
Depletion and depreciation	163.4	169.4	(4)
Write-down of petroleum and natural gas properties	10.4	31.3	(67)
Other (income) net	8.1	–	–
Current and capital taxes	2.9	9.1	(68)
Future income taxes	(62.2)	(46.9)	33
Net earnings	$ 2.6	$ 10.3	(75)
Net earnings per common share – basic	$ 0.04	$ 0.17	(76)

CASH FLOW RECONCILIATION

	2003	2002	Change (%)
Net revenue	$ 299.3	$ 399.5	(25)
Expenses			
Operating	81.2	86.1	(6)
Cash interest	19.7	23.9	(18)
Cash G&A	18.7	15.9	18
Lease rentals	3.6	4.6	(22)
Bad debt expense	5.9	–	–
Current and capital taxes	2.9	9.1	(68)
Cash flow	$ 167.3	$ 259.9	(36)
Cash flow per common share – basic	$ 2.78	$ 4.37	(36)

COMPANY FORECAST 2004

Production / Pricing		
Gas (MMcf/d) ($/Mcf)	160 @ $	5.68
Oil/liquids (Bbl/d) ($/Bbl)	6,000 @ $	US 28.00
Cash flow ($MM)		240
Cash flow per share		4.00
Capital budget ($MM)		240

COMMON SHARE DATA

Shares of Paramount Resources Ltd. trade on The Toronto Stock Exchange under the symbol "POU" (Oil and Gas Producers Sub Index) and is part of the S&P/TSX Composite Index.

At December 31	2003	2002
Outstanding shares (000s)	60,095	59,459
Public float[1] – shares (000s)	27,818	27,480
– % of total shares	46%	46%
Trading volume (000s)	34,335	21,027
Trading value (000s)	$ 431,533	$ 319,369
Trading range		
High	$ 16.95	$ 17.60
Low	$ 8.51	$ 13.00
Close	$ 10.45	$ 15.00
Weighted average trading price	$ 12.57	$ 15.19
Market capitalization at year end ($ millions)	$ 628.0	$ 891.9

(1) Public float is all outstanding shares less shares owned/controlled by officers/directors.

DIRECTORS AND OFFICERS

C.H. (Clay) Riddell[3]
Director, Chairman
and Chief Executive Officer

B.K. (Bernard) Lee
Chief Financial Officer

J.H.T. (Jim) Riddell
Director, President
and Chief Operating Officer

C.E. (Chuck) Morin
Corporate Secretary

L.M. (Lloyd) Doyle
Corporate Operating Officer

C.G. (Cal) Folden
Corporate Operating Officer

J.S. (Scott) McDougall
Corporate Operating Officer

G.W.P. (Geoff) McMillan
Corporate Operating Officer

J.B. (John) Williams
Corporate Operating Officer

L.A. (Laurel) Friesen
Assistant Corporate Secretary

J.C. (John) Gorman[1][4]
Director

D. (Dirk) Jungé, C.F.A.[4]
Director

D.M. (David) Knott
Director

W.B. (Wally) MacInnes, Q.C.[1][2][3][4]
Director

V.S.A. (Vi) Riddell
Director

S.L. (Sue) Riddell Rose
Director

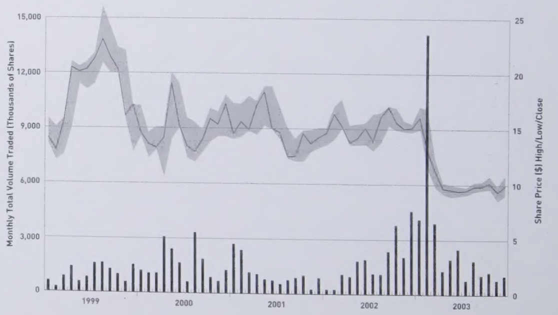
J.B. (John) Roy[1][2][3][4]
Director

A.S. (Alistair) Thomson[1][4]
Director

B.M. (Bernie) Wylie[2]
Director

(1) Member of Audit Committee
(2) Member of Environmental, Health and Safety Committee
(3) Member of Compensation Committee
(4) Member of Corporate Governance Committee

FIVE-YEAR SHARE PRICE AND TRADING VOLUME



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